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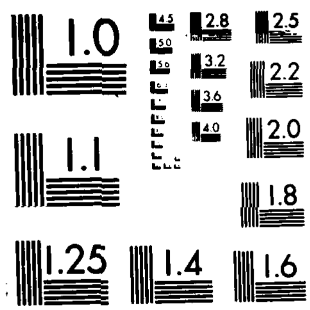

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A RAND NOTE

THE COSTS OF CLOSING NUCLEAR POWER PLANTS

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PREFACE

This Note discusses the basic cost concepts associated with the closure of nuclear power plants, reviews current cost estimating practices, identifies and demonstrates needed improvements in those practices, and develops and illustrates a useful matrix form for organizing and presenting the elements of closure costs. The discussion concerns only cost issues. It does not consider safety, health, or environmental issues; fuel-cycle costs; or issues concerning the ultimate disposal of nuclear fuel.

This study should interest the owners and managers of both publicly and privately held utilities; members of the Nuclear Regulatory Commission and other federal- and state-level regulatory agencies; and public-interest groups and private citizens concerned with issues of energy supply, the costs of electricity, and the economic consequences of closing nuclear plants.

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SUMMARY

Several years ago Stucker, Batten, Solomon, and Hirsch (1981) surveyed the then-available literature on the costs of closing the Indian Point (IP) nuclear facilities and found no consensus on the costs that should be considered in closure analyses, the use of present-value calculations, the projection of inflation rates or other driving assumptions, and no recognition of the fact that costs differ depending on the viewpoint of the analyst or decisionmaker. That study concluded that the uncertainty associated with current cost estimates was such that reasonable estimates might project the present value of the costs to be as low as $7.7 billion or as high as $17.4 billion in 1980 dollars. That corresponds to a range of $10 billion to $23 billion in 1983 dollars.

Examination of newer material now indicates a consensus on general procedures for estimating the *direct* costs of closure, on the need for computing present values based on the full potential economic life of the units, and on the use of reasonable and explicit inflation and discount rates. Occasionally, ~~some~~ other types of costs are ~~now~~ discussed, but even when recognized and quantified reasonably well, analysts ~~still~~ hesitate to include anything other than direct costs in their bottom-line calculations.

Estimates based on the best information ~~now available~~ place the present value of the direct costs of closing ~~IP~~ in the vicinity of $5 billion in 1983 dollars. Regional costs and transfers could easily raise the *local* impact of the closure substantially. Other sections of ~~the~~ United States would, of course, recover the majority of those effects as local benefits for their ~~respective~~ regions. The net (unrecovered) portion of these costs should be counted in computing total closure costs. If ~~the~~ closure of nuclear facilities requires increased purchases of petroleum products from other nations, the net U.S. cost will be correspondingly higher.

Estimates of closure costs still contain major uncertainties. Recent estimates of the direct costs of closing IP, documented in the report of the Atomic Safety and Licensing Board (ASLB 1983), range from a low of less than $1 billion to a high of $9 billion, although most are between $4 billion and $6 billion. Capital costs--defined in this Note as changes in the rate of return demanded by investors--and secondary costs--mainly the regional effects induced by the direct closure activities and costs--are at least equally uncertain. An NRC-mandated closure of an operating nuclear power plant could change the risk perception of investors to such an extent that the owning and operating utilities, and perhaps other utilities with similar plants, would be unable to raise construction or operating funds. Secondary cost estimates, whether computed as simple factors of the direct costs or with complex regional models, are quite sensitive to regional economic and social conditions.

Another major problem with the current studies, and one which is seldom discussed even when it obviously contributes to significant variance in the size of the different estimates, is their failure to consider distributional issues. The closure of a nuclear power plant in central Missouri can involve costs and benefits incurred in many states and even perhaps in foreign nations; but the voices heard at closure proceedings have more parochial views: Utilities are concerned with their required revenues, unions with local jobs, consumers with local prices, environmental groups with safety and disposal issues, and politicians with their local constituents. To date, neither the public authorities nor the public-interest groups have distilled the concerns of these organizations to reveal the broader interests involved. One contribution of this Note is the development and illustration of a matrix form for organizing ~~and presenting~~ the elements of closure costs. Use of the matrix encourages the assignment of costs to the particular social or economic group they will burden; it identifies the cost trade-offs that may exist between and among the different groups; and it reveals the extent or limits of particular estimates. It is recommended that such a matrix be required for all costs presented in closure proceedings.

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I. INTRODUCTION[1]

Nuclear power plants are under attack on many fronts. Safety remains the overriding concern, but during the last 10 years economic issues have become increasingly important. EIA (1983) reports that increased safety requirements, a less than anticipated increase in the demand for electricity, and sharply rising construction costs have combined to result in the cancellation of over 100 nuclear units since 1972, 18 of which were actively under construction. Even plants nearly ready for commercial operation are being questioned. The Diablo Canyon facility in California and the Shoreham facility on Long Island have become major political and social as well as economic issues. Diablo Canyon had its newly-issued operating permit revoked when design and construction errors were identified, while Shoreham has been challenged by county officials who refuse to participate in formulating and implementing emergency preparedness plans.

Plants that have been generating electricity for years are also being challenged. The 1979 accident at the Three Mile Island (TMI) nuclear power plant raised serious questions as to the advisability of siting nuclear facilities near large population centers. Since then, the Nuclear Regulatory Commission (NRC) has been reviewing power plant siting criteria and the safety records of a number of plants. The Indian Point (IP) facility near New York City and the Zion facility near Chicago have received special attention.

On the other hand, studies released recently by the Environmental Protection Agency and the National Academy of Sciences warn that the "greenhouse effect" may already have begun to warm up the planet. These studies recommend that means be found to lower our reliance on fossil fuels, the burning of which is thought to contribute to the greenhouse effect. Closure of nuclear generating facilities would further contribute to this problem.

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[1]An earlier version of this Note appeared in *Progress in Nuclear Energy*, 14, 2, 1984, pp. 137-164. Valuable comments and reviews were received from Norman J. McCormick, William E. Mooz, Michael P. Murray, and Kenneth A. Solomon.

These conflicting social issues and the increasing drive of political-action groups pressing for closure initiatives continue to increase the need for dispassionate consideration, review and reappraisal of power-plant closure costs.

This Note addresses the economic issues that would be associated with the closure of an operational nuclear power plant. On-line nuclear plants typically are producing electricity at lower cost than other forms of generation except hydro. Closure of an operational plant then would involve trade-offs between increases in generating costs, changes in other costs associated with the closure, and changes in safety and environmental hazards. This Note only considers the dollar costs of closure--direct costs associated with alternative generation and with the on-site closure activities, and external or secondary costs caused by the closure decision or by the direct cost elements. Safety considerations and environmental benefits or costs associated with power production by nuclear or other means are not covered.

A COSTING FRAMEWORK

The term *closure costs* as used here covers all of the extra or differential costs that would be incurred if a nuclear power generating facility were to be shut down before its scheduled retirement date. Closure costs include the costs of generating the required electricity at another facility, the costs of decommissioning the nuclear facility and disposing of the spent fuel, any incremental capital costs that are incurred, and all regional effects that are not offset by gains elsewhere. Any savings that would result from closure must be subtracted from the other items to obtain the net cost of closure.

Only differential costs are meaningful in estimating the economic costs of closure. Costs incurred whether or not the units are closed represent *sunk*, or unavoidable expenses. In particular, expended construction payments for generating buildings and equipment are sunk. A plant that has been built must be paid for by someone, either ratepayers, investors, bondholders, or taxpayers.

Stucker et al. (1981) proposed classifying all closure costs into four broad categories: alternative generating costs; one-time costs; business or capital costs; and secondary costs. Alternative generating costs represent the most important direct component of closure costs. Construction costs for nuclear plants have been increasing rapidly, although their operating costs are still relatively low. Closure thus requires that nuclear-generated electricity must be replaced by higher-priced generation. Indeed, if lower-priced electricity had been available, it normally would have been used.

One-time costs are also direct costs of closure. They include all of the costs of decommissioning the nuclear facility and disposing of the spent fuel. These costs, however, must be expressed net of the one-time savings associated with the now-planned activities and back-fits that will not be needed if the nuclear plant is shut down.

Capital costs, referred to as business costs by Stucker et al., include all of the incremental financing costs and dividend payments that may be incurred if the owning and operating utilities attempt to remain viable and to continue to supply electricity after the nuclear units are shut down. Note that these are general costs experienced by the utility (or by other utilities) because of its reduced solvency and financial base; they are not direct costs. Note particularly that increased construction costs and the financing required to provide alternating generating capacity should be considered as part of alternative generating costs.

Secondary costs are the regional costs that are induced by, or flow from, the imposition of the other costs. For example, increased local revenues from construction or generation activities usually result in the expansion of local service industries. Local employment in generating plants or in decommissioning activities promotes secondary employment in support industries--food, auto, clothing stores, etc. These costs are easy to conceptualize but difficult to estimate and aggregate correctly. Extreme care must be taken to ensure that overlapping costs are sorted properly and that double counting is avoided.

Table 3

PRESENT VALUE OF ADJUSTED GAO ESTIMATES

(In millions of 1980 dollars)

	1981-2011 Costs	
Category	Sum	1980 Present Value
Alternative generation costs		
IP	8.57	4.93
Zion	4.73	2.68
One-time costs		
IP	0.20	0.33
Zion	0.03	0.12
One-time savings		
IP	0.22	0.18
Zion	0.19	0.14

SOURCE: Computations on adjusted GAO data. Present values were discounted using a 5 percent annual rate.

decommissioning costs.

All of the costs discussed so far would be incurred initially and directly by the utility companies.[7] They do not, however, represent the net economic effect on society. Several energy-economy interactions affect the transformation of direct costs into net effects; two of the major ones, demand effects and secondary effects, will be discussed next.

DEMAND EFFECTS

When nuclear-generated electricity is replaced by higher-cost electricity, many users have options other than simply paying the increased rates. Some may reduce their electricity consumption by switching to other forms of energy, implementing cogeneration options, or simply going without. To the extent that these alternatives save

[7] The utilities would not ultimately bear the burden of the costs, of course, since they would pass them along to others.

THE PRESENT VALUE OF CLOSURE COSTS

To construct an estimate of the costs associated with a particular closure decision and express it in such a way that it can be compared with costs of other policy options involves discounting the costs that will be incurred in years later than some base year (here 1980) and calculating the present value of the cost stream.[5]

The estimates discussed above were not discounted, which effectively means they are based on an implicit net discount rate of zero. The procedures used here allow for the investigation of alternative discount rates, and for the simultaneous consideration of discounting and inflationary adjustments. These will be discussed further in Sec. IV. Here we discount at a single, positive rate. Current as well as past experience indicates the appropriateness of a positive rate of net discount--yields on most investments, including tax free accounts, continually outpace the inflation rate.

Discounting the (inflation-free) cost-profiles of Table 2 at a conservative rate of 5 percent per year yields the present values shown in Table 3. Note that the discounting process sharply reduces the values of the alternative generation costs since many of those costs will be incurred relatively far in the future.[6] The one-time savings are affected less by discounting since most are scheduled in the early 1980's. Net one-time costs would actually increase when discounted, because early closure would attach more current-value weight to the

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million for spent-fuel disposal, a $157 million loss on unused fuel, and a $41 million loss on other contracts, all assumed written off in 1981. One-time savings include $65 million for safety modifications and $13 million for radiological emergency response planning, both spread over 1981-1984, and $145 million for major plant repairs scheduled for 1985. The Zion costs consist of $98 million (1980$) for dismantling spread over the first 6 years of closure, $57 million for fuel disposal in the first year, and $25 million in contract termination costs spread over the first two years of closure. All but the contract termination costs will be incurred if the plant operates until 2006. One-time savings for Zion consist of $120 million in modifications and $6 million for radiological emergency measures, both distributed over the 1981-1985 period, and $60 million for chemical cleaning in 1988, 1995, and 2002.

[5] Discounting is *not* the same as adjusting for inflation. Even if the anticipated (and actual) inflation rate is zero, a dollar in the hand is worth more than a dollar to be received next year.

[6] With a discount rate of 5 percent, costs incurred 14 years in the future are valued at just about 50 percent of their then-year value.

Table 2

ESTIMATED TIME-PROFILE OF INCREMENTAL COSTS ASSOCIATED WITH THE IMMEDIATE CLOSURE OF INDIAN POINT AND ZION

(In millions of 1980 dollars)

	Alternative Generation Cost		One-Time Cost		One-Time Saving	
Year	I.P.	Zion	I.P.	Zion	I.P.	Zion
1981	457	270	306	86	20	25
1982	428	227	25	28	18	25
1983	361	200	25	17	19	26
1984	396	164	25	17	18	25
1985	361	128	25	16	145	25
1986	311	145	25	16	0	0
1987	248	189	0	0	0	0
1988	284	189	0	0	0	30
1989	310	189	0	0	0	0
1990	366	189	0	0	0	0
1991	344	189	0	0	0	0
1992	355	189	0	0	0	0
1993	352	189	0	0	0	0
1994	349	189	0	0	0	0
1995	346	189	0	0	0	15
1996	343	189	0	0	0	0
1997	340	189	0	0	0	0
1998	337	189	0	0	0	0
1999	334	189	0	0	0	0
2000	331	189	0	0	0	0
2001	328	189	0	0	0	0
2002	325	189	0	0	0	15
2003	322	189	0	0	0	0
2004	320	189	0	0	0	0
2005	317	189	0	0	0	0
2006	0	0	-108	-73	0	0
2007	0	0	-25	-16	0	0
2008	0	0	-25	-17	0	0
2009	0	0	-25	-17	0	0
2010	0	0	-25	-16	0	0
2011	0	0	-25	-16	0	0
	8,565	4,725	198	25	431	186

SOURCE: Computations on material from the GAO Indian Point and Zion reports.

The adjusted data must next be extrapolated to cover the additional years until the planned plant closures. The New York Public Service Commission has allowed ConEd to adopt a 27-year remaining service life for depreciation purposes of IP-2. We take that to mean that the currently planned starting date for decommissioning activities is the year 2006. To account for this full period we add an additional 13 years of costs by estimating the trend of the available adjusted 12-year costs. This yields an estimate of incremental generating costs for the entire 1981-2005 period.[1]

Zion, the GAO suggests, will be closed sometime in 2004 to 2009 if allowed to operate according to present plans. For comparison purposes, then, we can assume that normal decommissioning activities will start in 2006, the same as at Indian Point. The regression approach to extrapolating alternative generating costs fails here, however; only 6 data points are available and they indicate no reasonable trend. We use instead the average of the six available years.[2]

Columns 2 and 3 of Table 2 show the synthesized profiles of generating costs for Indian Point and Zion. Table 2 also contains estimates of the time profile of one-time costs and savings. These one-time costs are allocated as closely as possible to the years indicated in which they would occur, and then discounted by 14 percent to deflate them from 1981 to 1980 values.[3] Note that although one-time costs receive a major share of the attention in most closure studies, they represent only a minor portion of total costs.[4]

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[1] The regression equation gave a slope coefficient of 2.955 year, with an R-square of 0.04 and an equation F statistic of 0.44, neither of which is statistically significant. Projecting with the average rather than the trend would have increased the 25-year total by $232 million, or slightly less than 3 percent.

[2] The Zion estimates are based on those in Table 1, less a 6 percent allowance for taxes, and deflated at 9 percent per year to remove fuel and operating cost inflation.

[3]Conversions among 1980, 1981, 1982, and 1983 costs are made using the producers' price index for electrical power published by the U.S. Department of Labor: 1980 = 321.6; 1981 = 366.8; 1982 = 406.5; 1983 (June) = 419.7. These translate into inflation factors of 14.1 percent for 1980-1981, 10.8 percent for 1981-1982, and 3.2 percent for 1982-1983.

[4] The one-time costs for Indian Point consist of $150 million (1980$) for decommissioning and dismantling spread over 6 years, $83

III. FURTHER COSTING CONSIDERATIONS

The comparisons of the GAO studies for IP and Zion discussed above provide interesting and relevant information for further costing exercises. This section begins the transformation, expansion and updating of that data. Four major types of analyses will be described here: the economic life of the plants, present-value calculations, demand substitutions, and secondary impacts. These topics will be discussed in turn.

ECONOMIC LIFE OF THE PLANT

We have looked at GAO cost estimates for the first six years of plant closure. However, closure will affect plant costs much further into the future than that, and all of those future costs must be considered.

GAO truncated its cost profiles, examining only 12 years of closure cuts for IP and 6 years for Zion. More properly, they should have estimated power needs until the end of the currently planned life of these plants. Without further runs of the complex operations and costing models used by the utilities, the only way we can transform the available costs into estimates of the full replacement power costs is by making the rather crude assumptions outlined below.

First, we make a number of minor reclassifications and adjustments to make the existing data consistent and comparable. The IP estimates need to be adjusted as follows: Multiply the fuel costs by the factor 0.87 to reflect the near consensus that future capacity utilization rates for IP would be closer to 60 percent than to the 69 percent assumed in the GAO report; second, deflate the fuel cost estimates by 9 percent per year to remove the GAO's assumption for fuel inflation; then remove $68 million annual O&M costs included for the years after the plants are decommissioned, since these costs would not be incurred if the plants were closed. Finally, remove all taxes that had been included in the replacement fuel costs. Similar adjustments are made to the Zion data.

GAO limited its consideration to the utilities' revenue requirements. Those revenue requirements reflect nearly all costs borne by the utilities but do not include costs borne by other entities. In particular, they ignore most regional costs. The GAO work, however, did provide the first independently estimated and reasonably well-documented accounts of closure costs for nuclear power plants, and, in spite of shortcomings, it provided the baseline for all succeeding estimates.

In the following section we will work with the GAO estimates, using them to illustrate the construction of more complete and consistent estimates of the full costs of plant closures. In Section III below we discuss a number of full-costing considerations that were beyond the scope of the GAO studies but that are vital components of decision-oriented cost estimates.

Neither report documents its generating-cost model adequately or attempts to interpret, explain, or justify its output.

The difference in capital costs is also unexplained. In the Indian Point study these costs were estimated by a consultant from Stone and Webster, and the GAO report contains little more than summary tables. The cost estimates presented in the Zion study that "reflect the full financial impact of closing Zion" apparently contain *no* allowance for incremental capital costs. GAO does suggest (on page 32 of the Zion report) that increased capital costs could result from closing Zion, and that such costs might be important.[8] But it then obscures the issue by indicating that such costs should not be counted because of uncertainty over whether the ICC would allow their inclusion in CECo's rate base.[9]

The uncertainty, then, may be less concerned with the existence of capital costs than with who should bear them. But those are separate questions (although the distribution of responsibility for costs can easily affect their level). And GAO's decision to ignore certain costs does not illuminate any of the underlying issues; it certainly does not allow GAO to present conservative, defensible cost estimates. By not including those costs in its estimates of total revenue requirements, GAO underestimates, perhaps substantially, the total costs of closure, the revenue that CECo will require to remain viable, and the quantitative impacts that may be passed on to the ratepayers, bond- or stockholders, or taxpayers.

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[8] "Revenue requirements could be increased beyond our estimates if investors demand a higher risk premium on CECo's securities when Zion is closed prematurely. A relatively small increase in the interest rate on long-term bonds could greatly increase revenue requirements in future years, particularly when CECo's need for large amounts of capital for its new nuclear units is considered. For example, a 1 percent increase in the interest rate on the $809 million in long-term financing planned for 1981 would amount to $8.1 million annually over the life of the security. Common stockholders could also demand a higher rate of return on their investment which, if granted, would further increase revenue requirements." (Zion report, pp. 32-33)

[9] "Any added costs due to higher interest rates or a higher rate of return on common stock will be heavily influenced by ICC decisions on how the costs of the Zion units would be treated in the rates if CECo is required to discontinue the Zion operations. Since there is no precedence for this kind of action, both ICC and investor responses are uncertain." (Zion report, p. 33)

CAPITAL COSTS

GAO estimated the capital costs that might be associated with the closing of the Zion facility to be quite small, less than 3 percent of total closure costs. On the other hand, it estimated the capital costs for the closure of IP to be nearly $5 billion during the first 6 years of closure, or more than 50 percent of the total costs for that period.[7] This difference is even larger than the difference in the size of the generating costs.

In the IP report, GAO states (p. iv) that incremental revenue requirements for the utilities include (in addition to the fuel costs) construction costs, financing costs, and dividend payments. Construction costs (incremental to the closing of IP) appear to be a relatively minor item since the utilities have both excess current capacity and several projects already programmed to be on-line by 1987, so there is little alternative to inferring that these costs consist almost entirely of increased financial requirements. The Zion report, on the other hand, contains almost no allowance for any of these financial costs.

SUMMARY OF THE GAO ANALYSES

GAO has constructed two cost estimates for closing large operational nuclear reactors before the end of their economic life. The first estimate is rather high, more than $9 billion dollars over the first 6 years of closure, and consists essentially of $4 billion in replacement generation costs and $5 billion in increased capital costs. The second is much lower, less than $2 billion over a similar 6-year period, and is composed almost entirely of costs for purchasing substitute power.

The difference in the costs of replacement power may be due to actual differences in the physical and economic options available in the two areas, or a major portion of it may be due to *ad hoc* assumptions specified for the costing models. The reports do not specify which.

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[7] The $5 billion estimate is for the full-pass-through case and is presented as comparable with the Zion estimates shown in Table 1. GAO also estimated a number of partial-pass-through cases for IP, just as they did for Zion.

were 1.2 cents per kWh for Unit 2 and less than 1 cent per kWh for Unit 3 in 1979. In that same year, oil-fired generation costs were between 2.5 and 4 cents per kWh for the ConEd/PASNY system (GAO 1980, p. ii). The large discrepancy between the cost of purchased and own-generated power is due, at least in part, to the fact that ConEd and PASNY's limited transmission system cannot carry much additional low-cost replacement energy to the metropolitan area and to the requirement that these utilities burn mostly high-cost low-sulfur fuel in their metropolitan units. In contrast, the Zion report projects that the replacement costs for the 11.6 billion kWh of electricity needed in 1981 would amount to just over $447 million, giving a cost per kWh of about 3.9 cents.[6]

ONE-TIME COSTS AND SAVINGS

The differences in one-time costs, although small in relation to the differences in the other categories of cost, are significant. The estimate for IP is over twice the size of the estimate for Zion. Stucker's (1981) investigation of the individual cost items discussed in the two reports reveals that GAO consistently estimated lower costs for Zion.

The same general trend held for the estimates of one-time savings. Although the totals for one-time savings differed by much less than did the totals for one-time costs, GAO provides a lower, more conservative, estimate for Zion on each item included. There are some unanswered questions here, but since these costs represent only small fractions of total costs for each facility they are of lesser interest.

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[6] Table 1 of the Zion report indicates that the average 1980 generation costs incurred by CECo were 0.7 cents per kWh for the Zion units, 0.8 cents per kWh for its other nuclear units, 2.5 cents per kWh for the coal units, 6.4 cents per kWh for steam-oil units, and about 9 cents per kWh for the oil and gas peakers. Total costs ranged from 3.3 to 19.8 cents per kWh.

operating near the 15 percent margin it and its regulators consider necessary. If Zion were closed, CECo would be forced to purchase nearly all of the replacement generation from other utilities.

Further study of the GAO reports reveals that assumptions concerning inflation and demand growth at the two facilities were also comparable. (1) The GAO Zion report indicates that inflation was factored into the Zion cost estimates at a rate of 9 percent a year; Appendix II of the IP report indicates that similar rates were used in constructing the IP estimates. (2) The growth rates of future demand for the two sites are even biased in favor of lowering IP's relative costs. GAO assumed demand would grow at the rate of 1.5 percent per year in computing the Zion estimates[4] while estimates for IP were based on an average annual rate of growth that appears to be less than 1.25 percent.[5]

These initial comparisons indicate that the differences in the GAO's estimates for IP and Zion do not arise because of plant size, usage, or assumed price changes, but must stem from factors external to the nuclear plants or from basic differences in methodology and estimating philosophy. Examination of the estimates of alternative generating costs and capital costs indicate where those major differences arise.

ALTERNATIVE GENERATING COSTS

Differences in the costs of generating replacement power account for just about one-third of the total difference in the estimated costs of closing Zion and IP. The IP report (p. 41) shows incremental 1981 fuel costs of $607 million for the generation of the 9.17 billion kWh needed to replace the IP generation, indicating a cost of about 6.6 cents per kWh. By contrast, actual generation costs for the IP units

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[4] In addition to the estimates reported in Table 1, GAO also estimates Zion costs for a 3 percent growth rate. Those costs, totaling $1.76 billion over the 6 years, will not be discussed in this Note since our primary interest is in bounding closure costs and the Zion 3 percent estimate falls between the two sets of estimates that we consider.

[5] Table 3-4 on page 35 of the IP report shows that total available power for the ConEd franchise area is expected to be 35,814,564 megawatt hours in 1981 and 40,947,477 megawatt hours in 1992.

Table 1

COMPARISON OF ZION AND INDIAN POINT COST ESTIMATES: THE FIRST 6 YEARS OF CLOSURE

(In $ billion))

Item	Zion	Indian Point
Generating costs	1.58	4.17
One-time costs	0.19	0.43
One-time savings	(0.13)	(0.22)
Capital costs	0.04	4.92
Total	1.68	9.30

SOURCE: GAO reports on Zion and IP.
NOTE: All costs are in undiscounted then-year dollars and include allowances for inflation. Closure of both facilities is assumed to occur at the end of 1980.

This difference of over a factor of 4 is quite surprising, especially since the two facilities appear so similar. The capacity of both IP units is 1836 MWe and their closure would require the replacement of, Taylor and Komanoff (1980) suggest, an average of 9.17 billion kWh of electricity per year. GAO (1981) reports that the Zion units, with a joint capacity of 2080 MWe, produced 11.8 billion kWh in 1980.

Some evidence, in fact, indicates that closure costs for Zion might be larger than those for IP. According to the IP report, the New York City area served by Consolidated Edison (ConEd) and the Power Authority of the State of New York (PASNY) currently has sufficient excess capacity to withstand the complete closure of IP while retaining a reserve margin of over 20 percent.[3] The Commonwealth Edison Company (CECo), owner and operator of Zion, on the other hand, is currently

[3] ConEd owns and operates Unit 2 at IP (IP-2), supplying power to New York City and Westchester County. PASNY is responsible for Unit 3 (IP-3), which supplies power to municipal users in the area and to other utilities.

II. GAO ESTIMATES OF CLOSURE COSTS FOR INDIAN POINT AND ZION

The GAO reports on IP and Zion present estimates of the costs that would be incurred if those nuclear facilities were to be shut down and decommissioned immediately. When they were issued, these studies represented the state of the art in estimating closure costs for nuclear power plants. GAO (1980), the IP report, issued in November 1980 as the first of its kind, was a pathbreaking work. But, like all initial efforts, it addressed more issues than could be answered at that time. GAO (1981), the Zion report, expected soon after the IP report but delayed until October of 1981, resolved some of those issues. It built on the knowledge and procedures developed for the IP report and on criticisms of that study by Brancato (1980) and Taylor and Komanoff (1980). However, the entire area of nuclear plant costing is still relatively new and the costs associated with nuclear power plants are so elusive that significant uncertainties remain.

The magnitude of these uncertainties is apparent as soon as we compare the estimates for the two sites. They are strikingly different (see Table 1). GAO projects that the extra costs incurred during the first six years after closure would be over $9 billion for IP but less than $2 billion for Zion.[1] The derivation of this table has been documented by Stucker (1982);[2] here we will only summarize the main components.

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[1] The IP report estimates replacement power costs for the years 1981 through 1992, assuming that the IP units would be shut down at the end of 1980. The Zion report contains estimates of replacement power costs only for the years 1981 through 1986. Apparently these study periods were based on the availability of data from rate proceedings and planning documents of the utilities. Table 1 compares the estimates for the first 6 years of closure at each site. In Section III we emphasize the need to analyze the full remaining economic life of each plant.

[2] The costs shown here differ slightly from those in Table 5 of Stucker (1982) because that paper was comparing GAO's assumptions for the two sites. Here the objective is to correctly estimate costs.

Section V, the final Section, builds on the earlier sections. Possible distributions of closure costs among regions and among ratepayers, stockholders, bondholders, and taxpayers are analyzed, and used to explain the differing views and estimates of closure costs put forth by public officials. Finally, the implications of these analyses and estimates for policy discussions relating to other power plants are discussed.

Each of the four categories of cost is important in determining one or more of the several measures of total closure costs. The remainder of this Note reviews and contrasts the publications that have dealt with cost issues for operational and under-construction power plants, synthesizes estimates for the full costs of closing several plants, investigates the uncertainty associated with the estimates, and demonstrates how the composition of "total" closure costs depends on the viewpoint of the reporter.

OUTLINE OF THIS NOTE

The remainder of this Note is divided into four sections. Section II reviews the initial studies conducted by the GAO of closure costs for nuclear power plants. These studies covered the IP and Zion facilities and were the first full-scale studies of closure costs. Information from the two reports is sorted into the four cost categories introduced above and compared across sites to illustrate the relative magnitude of the different costs and to suggest the range of uncertainty, associated both with the methodology and with the estimates, for each.

Section III introduces additional considerations into the costing framework, considerations that are essential if estimates of direct closure costs are to be transformed into estimates of the full costs of closure. Four major considerations--the planned operating life of the plant, the present value of future costs and receipts, demand substitutions, and secondary effects--are discussed and qualitatively assessed. This section begins the conversion and updating of the GAO data that will culminate in Section IV with estimates of total closure costs.

Section IV highlights the major forms of uncertainty that have been observed in the various estimates and attempts to roughly quantify their impact on total closure cost estimates. A number of cost estimates that were presented in testimony before the Atomic Safety and Licensing Board that recently investigated IP are discussed and compared with the adjusted GAO estimates.

money (or satisfaction) vis-a-vis continuing the prior uses and usage at the increased rates, the net effect of the closure of the nuclear facility will be less than the cost impact estimated by the utilities.

Quantifying these demand effects requires a familiarity with the economic measures of loss associated with the closure of low-cost supply facilities. This section introduces those measures by developing in simplified fashion the relationship between cost increases imposed by regulatory restrictions and the resulting decreases in economic welfare. This analysis, based on concepts formulated in Barzel (1976), has been applied in Stucker, Burright, and Mooz (1980) and elsewhere to estimate the relation of costs to benefits for public policy actions.

The analysis is concerned with the long-run equilibrium effects of cost increases. Short-run or transitory effects are not considered, and all external effects and disequilibrium considerations must be analyzed separately.

The welfare loss associated with a supply restriction can be defined as the reduction in well-being, expressed in current dollars, caused by the restriction. This loss can be approximated by the sum of the change in consumers' surplus associated with the purchase of electricity and the change in producers' surplus associated with its sales. Consumers' surplus is defined as the difference between the maximum price that a group of consumers would be willing to pay for some quantity of electricity, as represented by the vertical height of their demand curve at that quantity, and the market price that they must pay. Producers' surplus is the analogous measure for the sellers. It is most easily defined as their net profit (before income taxes), the difference between the price they receive for their electricity and the lowest price they could accept, usually their marginal costs of production.

Camm (1983) discusses the general relationships between demand functions and policy-induced changes in consumer surplus, concluding that no one measure of consumers' (or producers') surplus is superior in all situations. Empirically, he suggests that the various measures will yield very similar results unless (a) the good in question accounts for a very large share of an individual's total expenditures or (b) his use of the good changes markedly as his income changes. As those conditions are unlikely to apply to consumer purchases of electricity, the analysis below only discusses Marshallian uncompensated demand and supply functions.

Figure 1 illustrates these functions for a competitive market. In the absence of restrictions, the market is represented by the demand curve D and the supply curve C_0. Under the pressure of market forces, the industry produces at the point where supply price is equated with demand price, selling Q_0 units at a price of P_0, and earns a surplus represented by area (P_0ce). Buyers, in aggregate, obtain a surplus of (acP_0) on the Q_0 units they purchase.

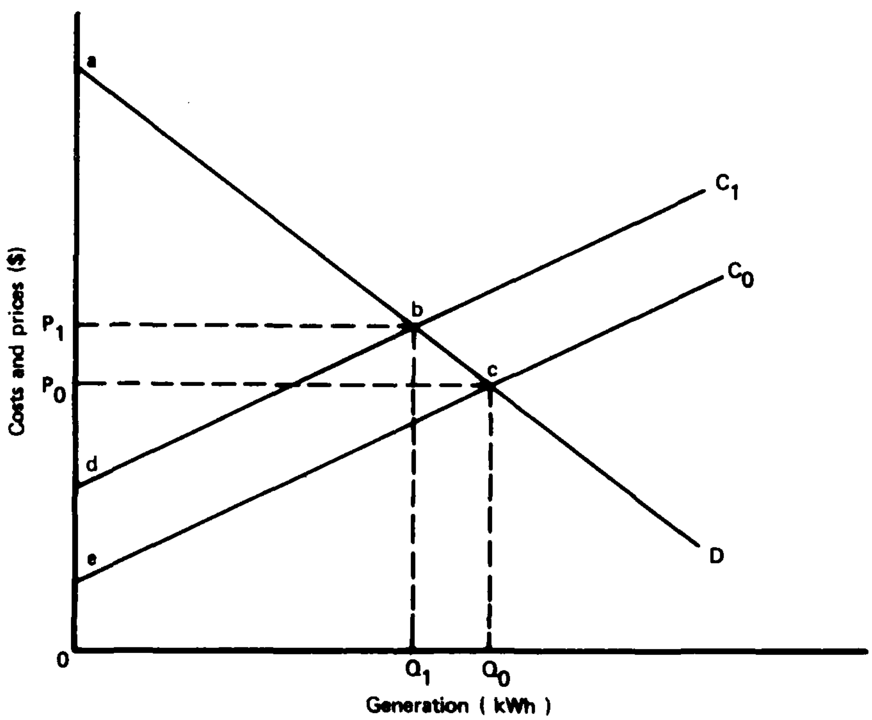

Fig. 1 -- Schematic of welfare loss associated with regulatory restriction on low-cost technology

The imposition of a restriction on the technology employed in generating the electricity causes the costs of generation to increase. This cost increase is represented in Fig. 1 by the higher supply curve, C_1. The market solution with the restriction in effect is represented by the generation and sale of Q_1 units at a price of P_1 per kWh. The industry now earns rents of (P_1bd) and buyers obtain a surplus of (abP_1). The welfare loss from the mandate is the sum of the decreases in consumers' surplus and producers' surplus.[8]

Figure 1 introduces the concepts involved in evaluating the economic costs of power-plant closure, but it is severely deficient in at least two respects: (1) closure of a nuclear facility will typically affect only a portion of the utility's supply of electricity; and (2) electricity prices are usually set administratively by the regulatory authorities rather than by the free workings of market forces. These topics will be discussed in turn.

Limited Nuclear Production

Figure 1 illustrated a simple case in which the entire supply of electricity is shifted from nuclear generation to a higher-cost technology. In most actual situations, however, and certainly for IP and Zion, existing nuclear generation represents only a small portion of the utility's total generation. Figure 2 illustrates such a supply schedule. In Fig. 2 the solid portion of the supply curve shows a simplified ranking of units when the nuclear facility is available. Hydro represents the least-cost fuel, followed by nuclear, coal, and finally oil. When the generation provided by the nuclear units is

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[8] Figure 1 is a comparative statics representation that illustrates the long-run "equilibrium" adjustments to closure, and says nothing about the actual dynamics of the adjustments. In the short run, substitution possibilities are relatively limited. We would expect a small portion of the adjustment to occur during the first year after closure, more in the second year, etc. This means that even though substitution may eventually reduce the incremental annual costs considerably, consumers will nevertheless incur substantial costs while the adjustments are being made. Mount and Tyrrell (1977) estimate that 20 percent of the remaining adjustment is accomplished each year. In a more general framework, Wright (1980) shows that the partial-equilibrium solution, as indicated by Fig. 1, will give an upper bound on the general-equilibrium increase in social cost.

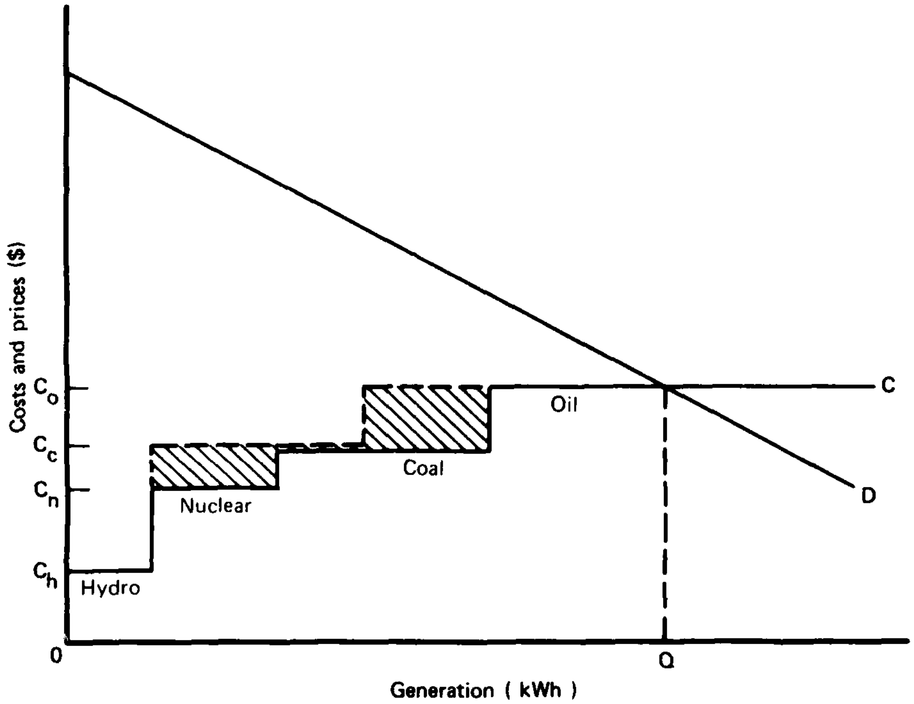

Fig. 2 -- Schematic of supply effect of closing nuclear facilities

removed, the supply ranking is as shown by the dashed lines. This curve is similar to the first except that the nuclear segment has been removed. The increased costs involved in producing without the nuclear units are shown as the shaded areas between the two cost curves. Note that the width of the two shaded boxes is the same, indicating that all the substitute power is produced by the highest-cost units--all the lower-cost units have been scheduled to capacity before the high-cost units were employed.

Figure 2 continues to assume that marginal-cost pricing is employed; that is, electricity is priced according to the generating costs of the highest-cost units employed. In the situation depicted there is no change in this cost, hence no change in price, and no change in sales or consumers' surplus. The full economic cost is represented by the change in generating costs. However, this will not normally be the case with actual power-plant closures because prices are typically based on average costs rather than marginal costs.

Regulated Prices

Prices set at other than marginal costs impose welfare losses of their own, as shown in Fig. 3. This case returns to the simple supply framework but assumes that regulation sets the market price at P_r rather than P_o. Lowering the price, and forcing the utilities to meet the increased demand, increases consumers' surplus but not enough to offset the reduction in producers' surplus. The price reduction shown in Fig.

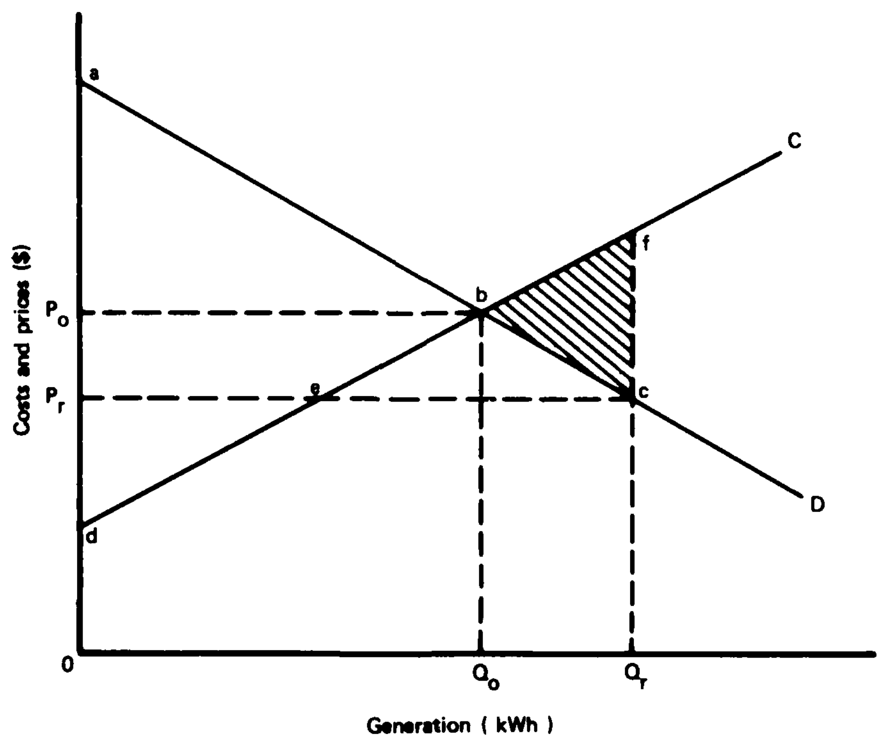

Fig. 3 -- Schematic of welfare loss associated with average-cost pricing

3 would increase consumers' surplus from (abP_o) to (acP_r), and would decrease producers' surplus from ($P_o bd$) to (($P_r ed$) minus (efc)). This yields a net welfare loss from the regulation of price and output equal to the area (bfc).

Now, closure of lower-cost nuclear units will increase average generation costs and, typically, cause some increase in electricity rates. Such a rate increase will reduce the distortion that regulation has been imposing on the market and tend to reduce the welfare loss.

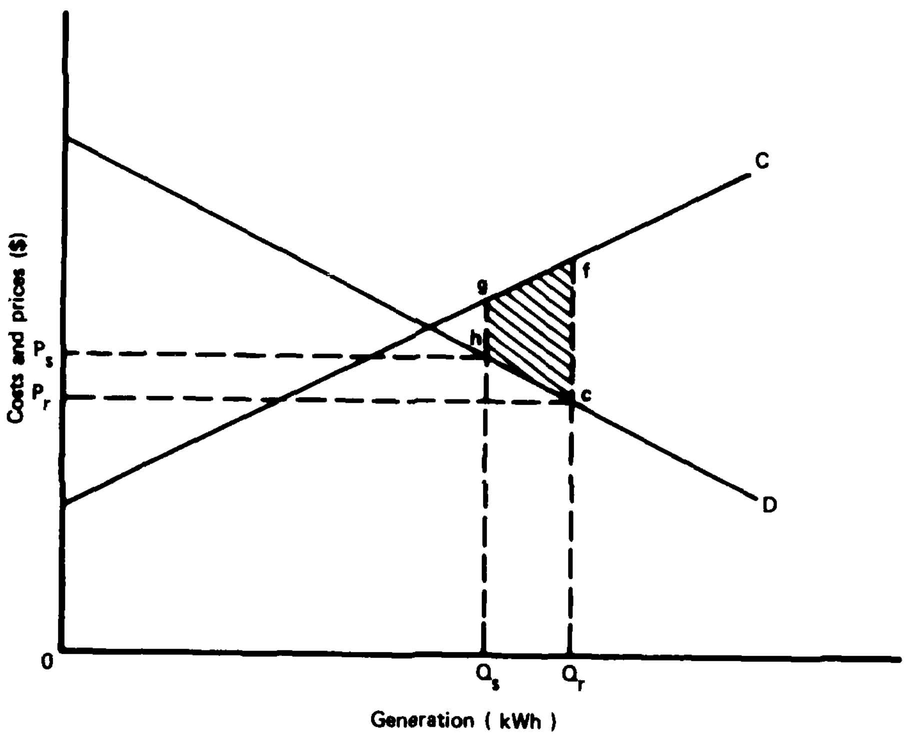

Fig. 4 -- Schematic of welfare loss gain when average-cost based prices move closer to marginal costs

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This is shown in Fig. 4. As the price is increased from P_r to P_s, the net loss is reduced by an amount equal to the area (gfch). Removing the low-cost units in effect reduces the gap between marginal and average costs, and the higher price discourages some of the excessive use of electricity.

Net Demand Effects

In general, then, the effects of demand or "price-induced conservation" on the computed costs of closure depend on the relation of nuclear generating costs to marginal generating costs, on the relation of nuclear-generated quantities to total generation, and on the relation of the increased costs to the allowed revenue increases.

For IP, even though excess generating capacity exists for the New York City/Westchester County area, shutting down the IP nuclear units would increase system costs because those units provide power at less cost than most of the alternative sources. Hydropower supplies a significant fraction of the electricity for the region rather cheaply, but expansions in hydro and greater imports of hydro-based power from the Northeastern states or Canada have always been limited. That leaves oil, natural gas, and coal as the fuel sources for alternative generation, and power from those sources costs appreciably more than electricity generated by in-place nuclear units. GAO (1980) reports that in 1979 the IP nuclear units represented about 16 percent of the total generating capability of ConEd and PASNY serving the New York City and Westchester County area. They obviously represent an even smaller percentage of the generating capability of the New York Power Pool (NYPP) to which ConEd and PASNY belong and which jointly attempts to minimize systemwide operating and capital costs.

Much the same situation exists for CECo in Illinois. In 1980 the generating capacity of the two Zion units represented only about 12.3 percent of CECo's summer generating capability even though, because they are used as baseload units, they accounted for almost 19 percent of the electricity generated by the utility (GAO 1981, p. 1). Under these conditions, the increased costs associated with closure of the IP units or the Zion units should be fully counted in calculating the economic costs of closure.

The welfare gains associated with reducing the divergence between marginal costs and average-cost-based prices would offset some of the loss associated with the increased generating (and one-time) costs, although usually only a small portion of it. The major impact of the price change is to transfer wealth from consumers to the utilities; the welfare gain is only a secondary effect.

It is easy to see that the price effect must be less than the cost effect. The welfare change associated with the price effect is the sum of the change in consumers' surplus and the change in producers' surplus. Any full pass-through case implies that the change in producers' surplus from the pricing action is designed to be equal to the cost increase from the closure action--which is the cost effect. Thus the price effect is the sum of an increase in producers' surplus, equal (but opposite in sign) to the cost effect, and a change in consumers' surplus which we know will be negative.

If less than full pass-through is allowed, the price effect will be even less, but in these cases a portion of the burden would be shifted to the owners of the utilities and perhaps to taxpayers or others. These groups would experience losses of income and well-being similar to those of the ratepayers.

In summary, most actual closure situations would involve both a limited amount of nuclear capacity and regulated prices. They probably also would involve external, local, and disequilibrium effects such as changes in capital costs and in regional impacts. Thus, the net economic loss of the closure would be composed of at least three separate effects: (1) the additional direct costs incurred by the utility (the alternative generation costs and the net one-time costs as discussed above); (2) less the welfare gains that result from the price changes; and (3) plus or minus any net changes in capital and secondary costs. The welfare gain arising from a rate increase is the only economic effect not discussed elsewhere in this Note. Its size is uncertain but it will be less, perhaps significantly less, than the change in the direct costs.

SECONDARY EFFECTS

Other, less-direct social costs would also be induced by the closure of a nuclear generating plant. The closure of a local generating plant will eventually reduce both spending and employment in the area, and this will lead to changes in sales, which will cause further cuts in employment and induce further effects throughout the economy. Some of these effects will be covered by the cost and demand analyses discussed above. For example, the impacts on intermediate suppliers and the direct consumption substitutions should be covered by the demand analyses.[9] Income and employment effects, however, are not covered by those analyses and need to be considered separately since they can be quite important in closure decisions.

Reduced employment in the nuclear generating facilities and reductions in disposable income due to higher electricity expenditures both tend to reduce local economic activity. Temporary benefits might accrue to the local economy while decommissioning activities increase the earnings of local residents, but longer-term effects of a less beneficial nature would be felt after the plant is closed and the decommissioning activity ceases. Of course, alternative generation (and perhaps construction) activities will stimulate other segments of the local economy, or other regions of the country, and these benefits must also be assessed and in the final tabulation offset against the local losses. The existence of these effects is generally recognized; their measurement is widely disputed.

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[9] Price effects should also be captured by the cost and demand studies. If the increased generating costs are passed directly through each succeeding stage of production, the total change in price, expressed as the change in the value of total production, will be equal to the increased generating costs. If some firms increase prices by more than their increased electricity costs, perhaps to retain their profit margin over costs, the additional increase will represent mostly transfer payments from buyers to sellers rather than additional resource costs. Some portion of the increased price may represent a real increase in resource costs, however, if it is used to cover, say, an actual increase in financing or working capital expenses. Those would be second-level effects, however, and should be well within the uncertainty level associated with the direct costs.

Secondary costs represent the lost surpluses in markets other than those directly affected by the plant closure and should be estimated as the value of the lost sales less the value of the resources used in generating those sales, with the resources valued at their opportunity costs.

In many government investment decisions, secondary benefits and costs are not considered at all because the decisions involve choosing among alternative projects, most of which would produce similar, and similarly difficult to measure, secondary effects.[10] This is often a valid and workable procedure. However, if the secondary effects involve different groups of workers (or other resources)--for example, workers in different regions of the country or in widely differing skill categories--their economic evaluations may not be even roughly equal. This can be especially true in situations involving the introduction or suppression of advanced technology.

The number of jobs that are lost by a plant closure is a common measure of economic and social impacts, and is often used by governmental decisionmakers. However, in addition to not being dimensionally commensurate with the other elements of closure costs, comparisons of job losses (or gains) may give inaccurate impressions of even the sign of the true economic change. The only proper measure of secondary effects is the loss surpluses, or the loss in value-added in the affected industries. The problem lies in empirically valuing the resources, especially the jobs, involved so that those surpluses can be determined.

If the resources that are released are fungible and in short supply, they will be quickly picked up by other businesses, and their full market values should be subtracted from sales in computing the lost surpluses. On the other hand, if, say, the workers are not immediately reemployed at a comparable wage, the loss calculations should value their wages at the level where they *can* find work, but not lower than the floor represented by either unemployment benefits or any reservation

[10]Feenberg and Mills (1980) contend that reducing taxes is at least a potential alternative in all government investment problems. This option would also stimulate the private economy, inducing secondary as well as direct effects.

level below which the workers prefer to stay at home. At the extreme, if all resources released in a secondary market remain (involuntarily) unemployed and no unemployment benefits are available, the loss should be valued at the full (former) value of the sales in that market for the duration of their unemployment.

SUMMARY OF ADDITIONAL COSTS

This section presented evidence that additional years of alternative generating costs should be included in closure-cost calculations, that all closure costs should be discounted to a base year in order to allow comparison with decision options, that the sum of alternative generating costs and one-time costs and savings provides a reasonable (higher bound) estimate of the direct economic costs of closure, and that secondary economic costs should be estimated by lost surpluses rather than lost jobs. Section IV discusses some of the uncertainties associated with such estimates.

IV. THE MAJOR UNCERTAINTIES

The discussions in Secs. II and III indicate that alternative generating costs, capital costs, and secondary costs probably dominate closure cost estimates and that major uncertainties are associated with each. Several of the more important uncertainties associated with those costs will be discussed next.

GENERATING COSTS

Alternative generating costs represent the major portion of all estimates of direct closure costs and, hence, are the main driver for all estimates of total closure costs. The GAO studies of Indian Point and Zion indicate that little new construction would be required to replace lost nuclear capacity at least in the short run; Taylor and Komanoff (1980) have argued that the alternative cost in the longer run would be the cost of newly built coal-fired plants. The major uncertainties here then include: (1) the cost of alternative generation from existing facilities; (2) the amount of alternative generation required; (3) expected inflation rates for the major alternative fuels; and (4) the expected costs of longer-run alternative generation either with existing facilities or with newly built coal-fired plants.

The Basic Estimates

As we have seen in Sec. II, GAO found large differences in the cost of replacement power for IP and Zion. The IP report shows incremental 1981 fuel costs of $607 million for the generation of the 9.17 billion kWh needed to replace the IP generation, indicating a cost of about 6.6 cents per kWh. In contrast, the Zion report projected that the replacement costs for the 11.6 billion kWh of electricity needed there in 1981 would amount to just over $447 million, giving a cost per kWh of about 3.9 cents.

An alternative estimate was provided by Taylor and Komanoff of the Union of Concerned Scientists (UCS). Using independent estimates of fuel costs, they estimated that replacing the IP generation in 1981 would cost \$337 million in 1980 dollars. Inflating this by 14.1 percent to express it in 1981 dollars yields an estimate of some \$385 million, or about 4.2 cents per kWh. More recently, a number of estimates were presented to the Atomic Safety and Licensing Board, which has been investigating the consequences of closing the IP units. Before discussing those estimates, however, it will be helpful to convert the GAO and UCS estimates to 1983 dollars. From this point on all estimates will be presented in comparable 1983 dollars.

Computing the 1980 present value of the generating cost profiles for IP and Zion contained in Table 2, by discounting them at a compounded rate of 5 percent, yields estimates of \$4.93 billion and \$2.68 billion (1980 dollars). Inflating those by 30.5 percent to allow for actual inflation between 1980 and 1983 changes the estimates to \$6.43 billion for IP and \$3.50 billion for Zion in 1983 dollars. Discounting the adjusted UCS estimates reported in Stucker et al. (Table 4) and then inflating the present value to 1983 dollars yields an updated UCS estimate of \$3.81 billion for IP. This estimate, however, covers only a 12-year period, 1981 through 1992.

The IP Atomic Safety and Licensing Board received testimony concerning alternative generating costs from witnesses representing its staff, the Licensees (ConEd and PASNY), UCS, New York City Council Members, New York State, and the Greater New York Council on Energy (GNYCE). Table 4 shows the estimates of direct closure costs presented by all of these groups except the licensees. Also shown is the adjusted GAO estimate derived above.

The Board's Staff and the UCS provide estimates that, when converted to 1983 dollars, come to just over \$5 billion. Witnesses for City Council members provided estimates of \$4.7 billion if low-sulfur oil is required, or \$2.9 billion if high-sulfur oil is allowed. These three sets of estimates consider alternative generating costs for essentially the full remaining life of the IP units. Estimates provided by witnesses for the State and for GNYCE, on the other hand, consider shorter periods. The GNYCE estimate, in particular, is substantially shorter and lower than the rest and deserves closer examination.

Table 4

ESTIMATES OF ALTERNATIVE GENERATION COSTS FROM CLOSING INDIAN POINT THAT WERE SUBMITTED TO THE ATOMIC SAFETY AND LICENSING BOARD

(Cost estimates in billions of 1983 dollars)

Source	Cost Estimate	Period Covered	Net Rate of Discount	Capacity Factor
GAO	6.4	1981-2011	5.0 percent	0.60
UCS	5.4	1980-2005	5.0 percent	0.57
Staff	5.2	1983-2006	5.0 percent	0.50
N.Y. City	2.9-4.7	1984-2009	?	0.54/0.48
N.Y. State	2.4	1984-1996	?	0.58
GNYCE	1.8	1983-1997	4.0 percent	0.55-0.20

SOURCES: GAO estimate from computations on data from GAO (1980) as described in text; GNYCE estimate from ESRG (1980), p. 61; all others from Atomic Safety and Licensing Board, Table XX, and accompanying text.

NOTES: Estimates have been converted to 1983 dollars using the producers' price index for electrical power published by the U.S. Department of Labor: 1980 = 321.6; 1981 = 366.8; 1982 = 406.5; 1983 (June) = 419.7. N.Y. City estimates based on capacity factors of 0.54 for Unit 2 and 0.48 for Unit 3. GNYCE estimates based on capacity factors that declined from 0.55 in 1983 to 0.20 in 1997.

Research for the GNYCE testimony was provided by the Energy Systems Research Group and is documented in ESRG (1982). Table 5 summarizes the ESRG estimates of the alternative generating costs for ConEd and PASNY if Indian Point is closed. Three sets of estimates are shown, each based on a particular set of assumptions. ESRG reports (pp. 6-7) that the High-Impact and Low-Impact scenarios were composed of assumptions "which consistently bias the results of the analyses toward higher or lower cost effects from closing the units," while the Mid-Range results are offered as best estimates of the direct cost effects of early retirement. Note that the High-Impact estimate is similar to the majority of estimates submitted by other witnesses to the Safety and Licensing Board and presented above in Table 4, while the others are substantially lower.

whenever a large generating facility is shut down. When the alternative power is generated with a foreign-procured resource, such as OPEC oil, the net U.S. costs may be substantial.

In summary, the secondary impacts associated with a power plant closure will probably contribute significantly to estimates of local closure costs. Multipliers are generally available from BEA to estimate the magnitude of regional effects within most of the U.S. However, local situations and circumstances vary among closure proceedings and across time to such an extent that all estimates of secondary costs must be viewed as very uncertain. Net secondary costs (estimated by netting several regional estimates) will be smaller than the local effect but can still be significant. The net secondary costs within the U.S. will be especially high if some of the benefits associated with the alternative generation are exported.

ESTIMATING UNCERTAINTY

These discussions indicate that the costs of closing even a much-studied facility like IP remain quite uncertain. Figure 7 attempts to summarize the evidence reviewed above. Alternative generating costs are the most important, the most direct, and the most studied components of closure costs, so they are taken as the standard. Remember that the discussions above indicate that the ranges illustrated in this figure should be viewed only as very rough indicators of the relative uncertainty associated with the listed factors.

The five bars on the left side of Fig. 7 represent estimates of the range that might be displayed by the factors contributing to the alternative generating costs. Properly constructed estimates for the first four of these factors should be distributed around a nominal expected value. Demand substitutions, on the other hand, will always tend to offset some portion of the generating cost estimate. The second group of items, the one-time costs and savings, capital costs, and secondary costs, represent the costs that must be added to generating costs in estimating the total cost of closure. The final portion of the figure represents that total and attempts to summarize the information contained in the component distributions.

analysis indicates that the uncertainty associated with the size of the secondary cost multipliers may not be as large as it first appeared. Even modest decay rates reduce the effects of the multipliers substantially: A 20 percent annual adjustment rate may reduce the effective multiplier by as much as 50 percent.

The Net Secondary Effect

The economy of a local area may be quite significantly affected by the closure of a nuclear generating plant. Taking a broader view, however, many of the local costs will be counterbalanced by benefits accruing to other regions. The *net* secondary impact can be either negative or positive, but we can expect it to represent a net cost unless the region surrounding the closed facility is relatively prosperous compared with the region(s) generating the replacement power. In general, a national economy such as the U.S. with moderate price rigidities, unemployment, and resistances to interregional flows of capital and labor, will experience some nontrivial level of net secondary costs

Table 6

EFFECTIVE MULTIPLIERS FOR IP AND ZION, BY SHORT-TERM MULTIPLIER AND ADJUSTMENT RATE

	Short-Term Multiplier				
Annual Adjustment Rate	1	2	3	4	5
Zero adjustment					
Indian Point	1.00	2.00	3.00	4.00	5.00
Zion	1.00	2.00	3.00	4.00	5.00
20 percent adjustment					
Indian Point	1.00	1.35	1.71	2.06	2.41
Zion	1.00	1.33	1.66	1.98	2.31
50 percent adjustment					
Indian Point	1.00	1.21	1.41	1.62	1.83
Zion	1.00	1.18	1.37	1.55	1.84

SOURCE: Computations performed on the time-profiles of direct costs for IP and Zion from Table 2, with all costs incurred after 1981 discounted at 5 percent per year.

The Local Secondary Effects

Multipliers are derived from interindustry transactions (sales) tables and commonly are used to relate the change in sales (or employment) in one sector to the total change in sales (or employment) for the region. To use such multipliers in estimating secondary closure costs, we must specify (1) the relationship between sales and surplus in the directly affected sectors, and (2) how the relationship of direct to indirect cost changes over time.

The simplest assumptions are that the relationships between sales and surpluses are similar in all affected sectors and that the relationship between direct and indirect costs remains constant over time. These assumptions will almost certainly overestimate the secondary effects, however. A slight tendency toward underestimation--because our estimate of the lost surplus in the electricity sector (composed mainly of the incremental costs of alternative generation) is based on a ready option and hence full opportunity costs, while the losses in the other sectors probably will involve some involuntary unemployment, at least in the short term--should be more than overbalanced by the inclusion of excess secondary costs for the later years.

Interindustry tables and the associated multipliers are essentially timeless; they indicate the immediate effects that would appear before any of the industries or consumers had a chance to adapt to the new situations. That is, they are essentially short-term disruptions. As time passes, the workers and firms adjust more and more to the new circumstances, learning new skills, adopting new processes, or perhaps moving to regions where they are more in demand.

The assumption that the relationship between direct and indirect costs remains constant over time is thus rather unrealistic. A more reasonable assumption would reduce the size of the multiplier over time. The implications of several adjustment (or decay) rates are analyzed below.

Table 6 shows the affects of applying different decay rates to the secondary costs that would be associated with IP and Zion closures; each adjustment rate is applied to a number of short-term multipliers. This affecting the economy of the Buffalo standard metropolitan statistical area--actually would stimulate output and employment in that region as firms order new energy-efficient equipment. That is, the cost increase benefits the area, and thus the multiplier is negative.

The other two sets of multipliers are more common. Those at or below unity (but still positive) usually are associated with long-run, national forecasting models. Those above unity are typically associated with models that have built-in rigidities such as fixed production coefficients and that are usually less than national in coverage.

Konsekvensutredningen (1980), the Swedish study, is probably typical of the former class. Earlier work by Bergman (1978) dealt with an equilibrium situation where unemployment was minimal and prices and wages were flexible. In addition, capital and labor easily substituted for all forms of energy. Given this framework, direct costs closely approximated total costs.

The other studies leading to Fig. 6 involve regional multipliers that are greater than unity, some substantially so: Henry's (1981) study of the effects of building a nuclear energy center in South Carolina uses a multiplier of 1.9; the New York City Regional Impact Multiplier System (RIMS) estimate is about 3.6[8]; and the multiplier implicit in the New York State Energy Master Plan (EMP) reported in Carey and LaRocca (1980) can be inferred as approximately 5.5.

These high-valued regional multipliers (all based on empirical data collected and processed by the Bureau of Economic Analysis (BEA) of the U.S. Department of Commerce) reflect the extreme sensitivity of local economies to expansions and contractions in basic employment industries and suggest that the secondary impacts of nuclear plant closures may be quite significant.

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[8] Evidence associated with the indirect-cost survey found that most of the multipliers estimated for cities, metropolitan regions, and states are in the 2.0 to 4.0 range. The overall multiplier for New York City is 3.74, the highest for any city in the nation, and individual multipliers associated with particular sectors of the New York City economy range as high as 4.6. In addition, Armstrong (1980) shows that many of the more important industrial sectors in the New York economy are associated with the highest sectoral multipliers.

principal effects imposed on the local economy by a closure decision and thus a dominant consideration for local officials.

The above estimates came from analyses that used various types of economic models to trace the interaction of costs, output, and employment, but in every case the final relationship between an initial cost increase and the resulting total change in output or employment could be summarized by a single factor called a *multiplier*. In general, a multiplier of this type is defined as the ratio of the total effect (the sum of the direct cost and the induced secondary effects) to the direct cost.

Representative multipliers from the more interesting studies surveyed are illustrated in Fig. 6. These multipliers fall into three classes, the first of which is highly unusual. The Savitt (1976) study suggests that increases in electricity prices--rather than adversely

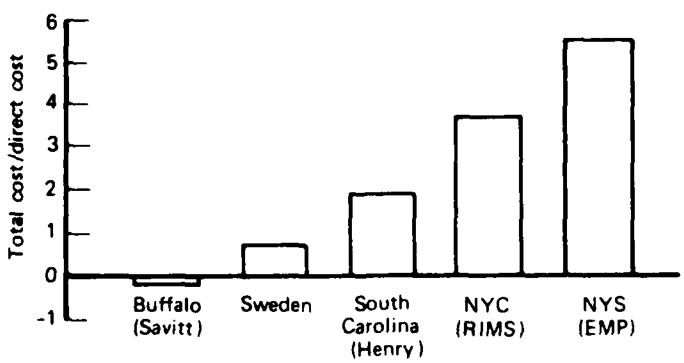

Fig. 6 -- Variation in size of multipliers

stock of the owning utility, General Public Utilities, fell from nearly \$19 a share in 1979 to less than \$4.50. The longer-term effect of closure, perhaps even more important, would be the obvious inference among investors that if one nuclear plant can be shut down they all can be. This would increase the risk premiums demanded by investors from all nuclear-owning utilities.

The implication here is that capital costs are important in plant closure decisions whether or not they are considered as true resource costs. One explicit aim of antinuclear advocates is to raise investors' perceptions of the risk associated with nuclear-associated investments to such a level that utilities can no longer consider those activities as viable sources of generation.

SECONDARY COSTS

Secondary costs also exhibit two types of uncertainty: uncertainty over the size of the gross regional impacts; and uncertainty over the net impact, the costs incurred in one region that are not offset by gains in other regions.

A survey conducted in 1980 (Stucker et al., 1981, Sec. V) found no published studies dealing with the secondary costs that would be associated with the closure and decommissioning of a nuclear power plant. Review of studies associated with somewhat similar situations, however, indicated that the cumulative induced effects might amount to 2 or 3 times the value of the primary effect, although estimates of 1.0 to 1.5 were more common.

More recently PASNY witnesses have testified before the IP Atomic Safety and Licensing Board that "if New York City's rate increases were absorbed through decreasing governmental services, a direct loss of 1620 jobs would result; and because of a multiplier effect (1.5 to 2), this loss could ultimately total more than 2500 positions" (ASLB, 1983, p. 374). Statements such as this suggest that secondary costs may be the

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regulatory lag would still cause severe financial pressures for the utility.

CAPITAL COSTS

GAO (1981, especially the Appendix), reports that its estimates of these costs for IP represent mainly increased requirements for financing costs and dividend payments, items which are not included anywhere in its Zion estimates. Many analysts contend that these items are not real costs of closure, but that they represent only transfers of money from one group of people to another; this may explain the GAO's change of policy between the IP and Zion reports.

We have then two forms of questions associated with capital costs: one concerning the magnitude of such costs, and another concerning whether they should be considered in tabulating the net costs of closure. The first question is essentially empirical, but the focus of the studies published so far has been less than clear. GAO's alternative approaches were discussed above. ERSG's procedure and findings are also interesting.

ESRG includes the "recovery of, and return on, invested capital" as a component of its estimates of required revenues from closing IP, and estimates they will amount to some $57 million (1981 dollars) in *savings*. Most of these savings will accrue from the reduced need for nuclear liability insurance after the units are shut down, the remainder from the earlier-than-expected tax write-off of the closed plants (ESRG pp. 5, 35). ESRG does not discuss the effect of the plant closures on the publicly perceived risk associated with the utilities' bonds and ConEd's stock.

Changes in bond yields and prices mainly represent financial flows between the individuals and organizations that hold those bonds, but they also affect the utilities' ability to raise new capital, support current working capital requirements, and even to remain in business. And if investors are as sensitive to plant closures as many analysts believe, these effects may spread to other utilities that have nuclear units being questioned.

One certain impact of the closure of an operational nuclear power plant would be to reduce the profitability of the owning and operating utilities. Extra costs would be incurred and not all of them would be recouped through rate increases.[7] In the aftermath of the TMI accident,

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[7]Even if all extra costs were ultimately found to be allowable,

GAO, considering only savings on currently specified repairs, modifications, and safety measures, estimated them as $220 million for IP and $176 million for Zion. This is 3 to 4 percent of the estimated generating cost. Taylor and Komanoff, on the other hand, include $150 million to $255 million for such items as new safety requirements, future safety improvements, study costs, and post-TMI safety mods. Still, however, their tentative upper estimate of about $475 million represents only 12 percent of their estimate of alternative generating costs.

ESRG is the only group to estimate that the savings will be significant. They estimate savings of more than $800 million even after being discounted to 1981 dollars. This is over 50 percent of their estimate of (discounted) alternative generating costs. In addition to $569 million on repairs, modifications, and safety measures they also estimate savings of $198 million for radioactive waste storage and disposal if IP is closed early, and savings of $60 million on decommissioning costs because less total radiation will be present in the property, buildings, and equipment.[5] ESRG's estimates differ from those of GAO and others in that every category of one-time impacts analyzed by ESRG is estimated as savings.[6] ESRG's lower closure costs for IP thus derive not from simple disagreement over one or two items but from a set of consistently lower estimates for all of the items considered.

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[5] ESRG appears to assume that decommissioning and dismantling will take place over the same time period whether IP is closed now or later, thus removing the normal tendency of the present-value calculations to indicate higher costs for the close-now case.

[6] Taylor and Komanoff estimated that the net impact of the one-time items would be a substantial savings, and that only one individual item--contract terminations--would represent a true cost. (See Stucker et al., pp. 29-30.)

No nuclear power-producing facility of even medium size has actually been decommissioned and dismantled yet, although some eight nuclear-powered submarines and a number of electricity-producing facilities, including the Humboldt Bay plant in California and IP-1 in New York, have been out of operation for a number of years, awaiting dismantling and disposal. Plans were recently announced (Wald, 1984) for the dismantling of the Shippingport reactor, the nation's first commercial nuclear plant. This 72-megawatt facility produced electricity and operated as a Government demonstration and test facility from 1957 through October of 1982. The closure project, to be carried out by UNC Nuclear Industries, under the supervision of the U.S. Department of Energy, is currently projected to cost $79 million (apparently in mixed 1986, 1987, and 1988 dollars), exclusive of disposal costs. How these costs would extrapolate to the case of a 1,000 megawatt reactor similar to those at IP or Zion is uncertain, as is the accuracy of the basic estimate.

The one ongoing empirical case we have suggests a higher figure, but one that is still relatively minor compared with the other costs discussed in this paper. Several years ago Governor Thornburgh of Pennsylvania proposed a $760 million joint federal-private-state cleanup plan for Unit Two at Three Mile Island (TMI). Since then, numerous sources have cited a $1 billion figure, and there has been little criticism of this as too high. Current costs seem to be running about $400 million per year. The situation at TMI is unusual and probably more expensive than a simple decommissioning. However, even one billion dollars for the decommissioning of IP or Zion would correspond to only 12 and 21 percent, respectively, of their generating cost estimates as reported in Table 3.

The one-time savings from closure appear at least as nebulous as the one-time costs. Some of these savings are attached to now-planned future repairs and modifications that can be costed somewhat accurately, but other, and from many viewpoints the majority, of these savings are attached to less than completely specified (and perhaps even some as yet unconceived) requirements that the NRC and other regulatory agencies will probably require the utilities to undertake.

replacement power costs, and, since we can have little confidence in current estimates of future operating ratios, this is a significant source of estimating uncertainty.

Construction Costs

Construction costs may also be a source of estimating uncertainty. GAO indicated that very little if any additional construction would need to be undertaken or rescheduled if either the IP or the Zion units were to be shut down, and they apparently include no differential construction costs in their estimates.

Taylor and Komanoff, on the other hand, argue that newly constructed coal-fired plants are the viable long-run alternative to nuclear generation, and estimate that those plants would produce the alternative power with about a 26 percent savings over the short-term oil-fired alternatives.[4] This 26 percent may represent a reasonable estimate of the upper bound in construction cost uncertainty.

ONE-TIME COSTS AND SAVINGS

Decommissioning costs as well as the savings associated with avoided backfits and modifications also possess elements of uncertainty. Although a few small nuclear reactors have been decommissioned in the United States, no major facility has yet been decommissioned and the available cost estimates are quite tentative.

GAO estimated that one-time closure costs for IP and Zion would be relatively small. Table 1 indicated GAO believes they might be as little as 10 percent to 12 percent of alternative generating costs, even when only the first 6 years of generating costs are considered. Viewed over a longer time span, GAO's one-time costs come to about 8 percent of their imputed alternative generating costs. Viewed in a comparable manner, Brancato (1980) indicates these costs also at about 8 percent of generating costs, while Taylor and Komanoff (1980) place them much lower, at perhaps 1 percent. (See Stucker et al., Tables 1 and 7, 2 and 8, and 3 and 9, respectively.)

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[4]This is comparing the short-run annual cost of $337 million from Taylor and Komanoff's (1980) Table 1 with the long-run cost estimate of $250 from their Table 2.

GAO based its work on operating ratios of 69 percent for Indian Point and on a range of ratios from 47 percent to 69 percent for the Zion units depending "on their availability, availability of other units, and system load." In Sec. III above we adjusted the IP estimates to reflect a more reasonable 60 percent factor.

Taylor and Komanoff were among the first to argue that GAO's use of the 69 percent ratio for Indian Point was too high. They presented data indicating that the average lifetime utilization of IP-2 and IP-3 has been 55 percent and 57 percent, respectively (through the first eleven months of 1980), and used a 57 percent factor in their alternative calculations. More recent figures reported in the New York Times (NYT 1983, pp. 1, 14) indicate that IP-2's ratio has increased to 56 percent but that IP-3's has fallen to below 48 percent.

ESRG analyzed capacity factor data on 68 commercially operating nuclear units in the United States for the years 1975 through 1981 and found a slight tendency for the capacity factors associated with larger, saltwater cooled, pressurized water reactors--such as those at IP--to increase over the first 6 years of operation (a maturation effect), to hold steady for several years, and then to decline.[3] Consequently, they predicted that the capacity factors for IP-2 and IP-3 would decline steadily from their 1982 levels until, at the end of 35 years of operation, they would be operating at 20 percent of capacity.

The significance of differing operating ratio assumptions is easily demonstrated. For example, replacing a nuclear plant that would operate at 69 percent of capacity for the remainder of its economic life would require 38 percent more electricity, and probably about that much more in costs, than replacing a plant that operated at only 50 percent of capacity. This is a very significant difference in estimated

[3] This finding, while probably valid, is currently based on rather scanty evidence. ESRG's data base contained only 9 units of interest, with the oldest being 14 years of age (ESRG, pp. 24-30 and Appendix C). ConEd responded in testimony before the Safety and Licensing Board that "When data for the existing 14 large salt water PWRs are reviewed, it is clear that steam generator problems in only three of those plants are responsible for all of the significant loss in the average operating times. Excluding data from small older units, the average capacity factor for all nuclear plants is 62.50%, and for all PWRs it is 65.81%" (ASLB, p. 362).

those costs.[1] The curves indicate the present value of generating costs when all costs incurred later than 1980 are discounted to that year. It is based on a constant discount rate of 5 percent. Present values are plotted for price changes ranging from 20 percent per year down to a negative 10 percent.

The curves in Fig. 5 vividly demonstrate that assumptions about future prices affect the cost estimates significantly. The IP profile is influenced slightly more than the Zion profile since its costs are spread more into the future, but both sets of costs have a similar enough sensitivity to the assumed price change for them to be summarized together: An assumed price-change rate of 5 percent yields a present value that is 75 percent greater than the present value that would be associated with zero price changes; an assumed 10 percent change rate yields a present value about three and one-half times the zero-change value; and a 15 percent rate yields a present value of costs that is over 7 times the zero-change value.[2]

If fuel prices should fall in the future, present values would also be significantly affected, but the percentage changes would not appear as large. A 5 percent decrease in fuel prices would reduce the present value of costs only about 35 percent; a 10 percent fall would reduce present values by just over 55 percent.

Operating Ratios

The assumed future operating ratio, defined as the ratio of the quantity of electricity actually produced by the nuclear unit compared to some theoretical maximum, is also quite important in computing total closure costs. A nuclear plant that is used very little obviously costs less to replace than one which operates nearly full time.

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[1] The real rate of price change is defined here as the rate of change in electricity generation costs less the general rate of inflation experienced by all goods and services.

[2] GAO constructed its original generating cost estimates for IP and Zion using about a nine percent annual rate of price increase. Thus, if those estimates were reported here they would be about three times the size of the adjusted values shown.

Figure 5 illustrates the uncertainty associated with the fuel price assumptions by relating the estimates of generating costs for IP and Zion derived above to the real rate of price change incorporated in

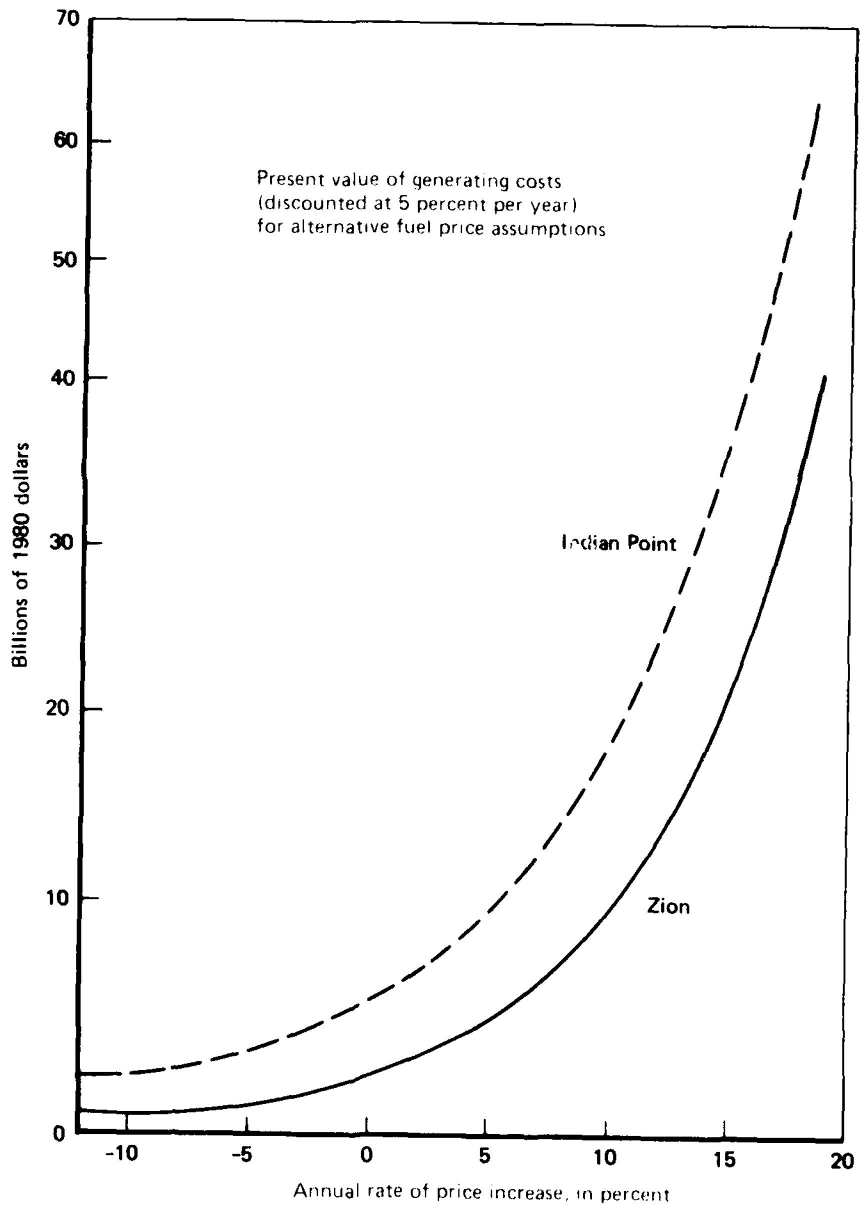

Fig. 5 -- Sensitivity of generating costs to increases in the price of fuel

Table 5

ESRG ESTIMATES OF ALTERNATIVE GENERATING COSTS FOR INDIAN POINT

(In billions of 1983 dollars)

Item	High-Impact	Mid-Range	Low-Impact
Costs of alternative generation			
Make-up generation costs	$ 7.42	$ 4.47	$ 2.24
Direct capital related costs	-0.07	-0.07	-0.15
Nuclear fuel	-0.78	-0.65	-0.43
Nuclear operation and maintenance	-1.88	-1.96	-1.96
Net cost of alternative generation	$ 4.70	$ 1.80	$-0.30

SOURCE: ESRG (1982), pp. 61-63. Entries have been increased by 14.4 percent to represent generating-cost inflation between 1981 and 1983.

ESRG adopted a short time horizon, and its assumptions on capacity factors and input costs can be seriously questioned. Nevertheless, the Mid-Range estimates, at least, deserve serious consideration since they are the best documented independent alternatives to the GAO work.

Finally, note that the more sophisticated estimates of alternative generating costs--the GAO estimates for IP and Zion and the ESRG estimates for IP in particular--rely on computerized scheduling and operations models to provide inputs for the costing models. Such combinations of models, if carefully constructed, calibrated, and operated, may be able to project costs and effects more accurately than less sophisticated methods. Unfortunately, it is currently very difficult to assess the accuracy and reliability of these models and their projections. Until strict standards of testing and documentation are required, estimates produced by utilities or others using complex, black-box methods must be viewed quite critically.

Price Increases

Possible future increases in generating costs, especially if petroleum prices should again rise sharply, represent a second major source of uncertainty. For the estimates shown in Table 3, all increases in fuel costs have been factored from the GAO data; and none is present in the ESRG estimates. All other estimates shown assume some level of price increase.

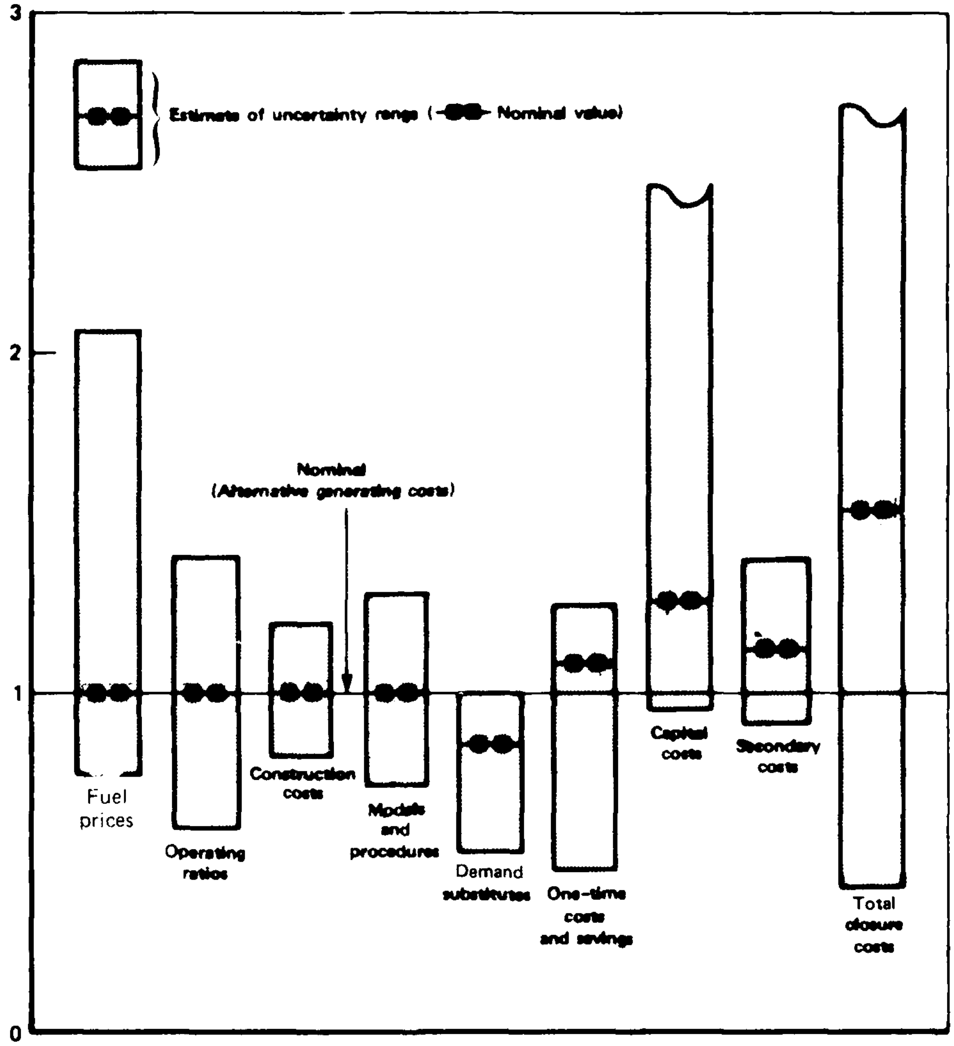

Fig. 7 -- Relative uncertainty of factors and components of closure costs

First, note that future fuel prices have been identified as perhaps the most critical component of future generating costs. We have seen that generating costs are also sensitive to assumptions concerning operating ratios and construction costs, but to a lesser extent. Costing and operations models, often "black boxes" even to those who use them, also contribute to the uncertainty of the generating cost estimates.

Demand substitutions in response to rate increases will provide gains to the utilities and reduce the net closure costs somewhat. The strength of this effect depends on the technical and financial alternatives available to the electricity users, on the actual behavior responses of those users, and on the timing of the responses. These factors are uncertain but this effect should seldom approach half the size of the generating costs.

Capital costs--defined in this paper as changes in the return demanded by investors--are at least as uncertain as generating costs. It may be that an NRC-mandated closure of one operating nuclear power plant would change the risk perception of investors to such an extent that other utilities would be unable to raise construction or operating funds for nuclear facilities. If this occurred, the external costs associated with the closure of the first facility could substantially outweigh the direct costs of that closure.

Estimates of both local secondary impacts for the regions most affected by the closures and of the net secondary impact when the local estimates are summed are also very uncertain. These estimates, however, have much more leverage on estimates of local costs than on the estimates of net total cost shown here.

To summarize, this section has attempted to determine reasonable upper and lower bounds on the calculation of individual elements of closure costs and on the total cost derived by summing the components. The procedure currently has severe limitations: The upper and lower values for the components must be crudely inferred from the often less-than-adequately documented work of various analysts, and the nominal values and the aggregation must be based at least as much on subjective evaluations as on objective comparisons. No statistical uncertainty distributions are stated or implied. Given those caveats, the evidence to date suggests that the total costs of closing an operational nuclear power facility would probably equal nearly 1.5 times the alternative generating costs estimated for the closure. However, estimating error and the realization of future events that differ from current predictions could easily result in the actual total cost being less than the generating costs or as much as 2 to 3 times that value.

V. THE FULL COSTS OF CLOSURE

The objectives of this final section are to summarize the estimates of closure costs discussed above, to illustrate how closure total cost differs depending on the point of view of the estimator or decisionmaker, and to discuss the general validity and usefulness of the procedures that have been presented.

SUMMARY OF CLOSURE COSTS FOR IP AND ZION

Stucker, et al.'s 1981 survey of the then-available literature on the costs of closing IP concluded that the costs might have a present value of as low as $10 billion or as high as $23 billion when expressed in 1983 dollars. Predictably, most of the analyses conducted since that time have focused on improving estimates of the direct costs. ASLB (1983) contains some 6 different estimates of direct closure costs for IP, while the GAO seems to be the only outside organization that has estimated the costs of closing the Zion nuclear facilities.

These studies seem to be converging on estimates of alternative generation costs. Unfortunately, they have not allocated equivalent resources to the study of either the capital costs or the secondary costs. Several reports have indicated these costs, at least the secondary ones, may be quite important; and several others have included estimates of property tax reductions that would result from plant closures. But, in general, the understanding of the non-direct costs lags substantially behind that of the direct costs.

The evidence now seems to indicate that:

- Alternative generating costs incurred by the closure of IP would amount to $4 billion to $6 billion 1983 dollars;
- Alternative generating costs associated with the closure of Zion would be slightly less, perhaps in the $3 billion to $4 billion range;

- There is still much uncertainty associated with these estimates, but many of the more significant factors would work to offset each other--for example, increases in fuel prices would increase the costs, demand substitutions would reduce them;
- One-time costs and savings would probably net to relatively small amounts, but there is some chance that the savings could be significant and could balance a significant portion of the alternative generating costs;
- The effects of closure on capital costs are quite uncertain and these costs could affect other utilities as well as the ones owning and operating the facility being investigated (these costs could be larger than the alternative generating costs);
- Secondary costs will be important to the local economy, but may largely balance out when netted against positive secondary effects experienced in other regions and countries.

Thus the evidence seems to indicate that the direct costs of closing Indian Point would be in the vicinity of $5 billion 1983 dollars and the direct costs of closing Zion would be about $3.5 billion. Secondary costs and transfers could easily raise the total *local* impact of the closures by 50 percent or more; and capital effects could be even greater.

THE EFFECTS OF TIMING ON CLOSURE COSTS

The estimates and discussions in the above sections illustrated that, although the differential cost of producing electricity at an alternative facility is the most significant direct factor in determining total closure costs, the timing of the closure is also extremely important. Closure of a unit that has only a few years of useful life remaining will be obviously less costly than closure of a unit that has the potential for producing low-cost electricity for another 20, 25, or 30 years.

Figure 8 illustrates the relationship between potential remaining life and direct closure costs using the IP data from Table 2. The plot compares relative costs for closure dates ranging from 1981, when the units have 20 years of potential operation ahead of them, through the year 2005, the last year of currently planned operations. In each case all of the future costs are discounted back to the assumed date of closure.

Closing the IP units in 1981 would have generated a present value of $6.6 billion in direct closing costs (1983 dollars). Delaying closure until 1985 would, under the same assumptions, decrease the closure costs by 35 percent. Delay until 1987 would decrease them by

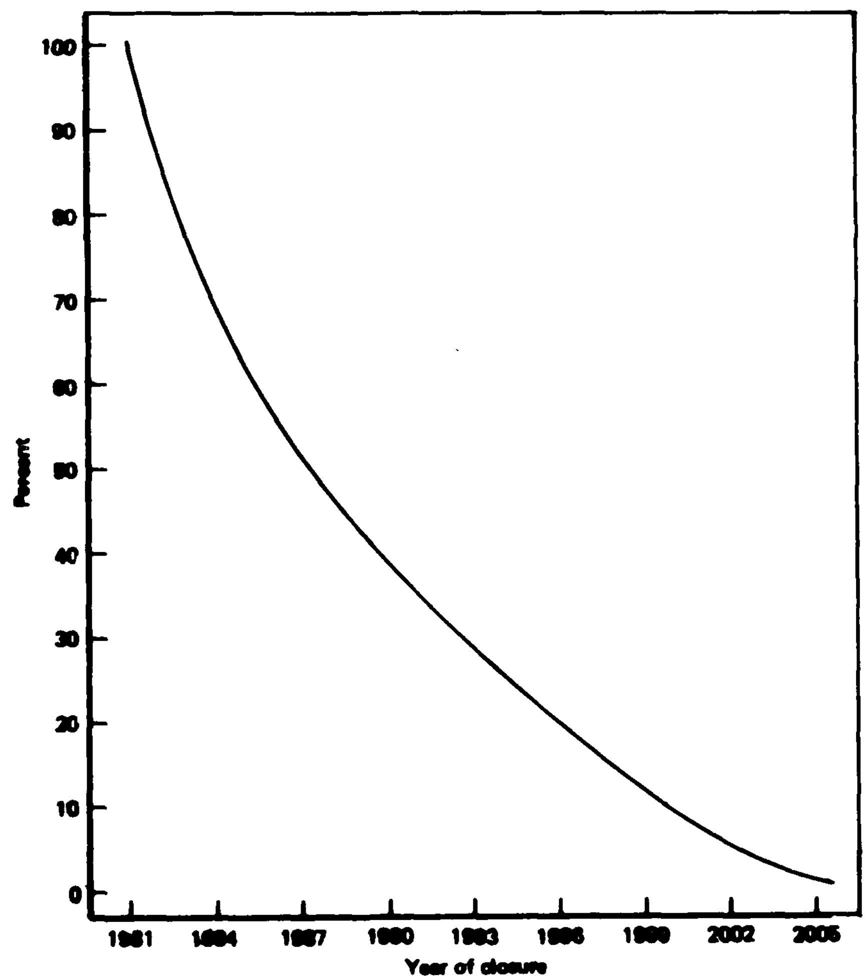

Fig. 8 -- Discounted closure costs for Indian Point, by year of closure, expressed as percent of the costs incurred with 1980 closure

nearly 50 percent, and delay until 1994 would decrease them to about one-fourth of their 1981 value. Since both generating and one-time costs are considered, this plot probably represents the general relationship between remaining life and closure rather well.

COST BURDENS AND THE NET COST OF CLOSURE

In addition to reacting to the influence of the uncertainties discussed in the sections above, closure costs will vary depending on the location of the closed facilities, the source and location of the replacement power, the source of fuel for generating the replacement power, the source of financing for the closure and the alternative generating activities, and the distribution of the costs of closure. For all of these reasons, it is possible for cost estimators to consider different sets of costs and reach different conclusions concerning closure.

Such differences, however, ensure that confusion exists concerning both the measurement of the "full" costs of closure and the ultimate distribution of this cost among ratepayers, shareholders, taxpayers, and others. Much of the ambiguity and confusion can be removed, however, if the distributional aspects of closure costs are handled properly. Tables 7 and 8 illustrate the use of a matrix format for displaying the component costs of closure. Such a format can be a major aid in understanding the different aggregations of cost and the implications of those aggregations. Both tables contain hypothetical but suggestive values for component closure costs and differentiate between the parties that bear portions of these costs.

Table 7 illustrates a possible distribution for a full-pass-through case for IP. Here all costs incurred by the local utilities are passed directly through to their ratepayers. Table 8 illustrates similar closure costs when the utilities are allowed to pass only one-half of their increased costs along to the ratepayers. The reader should remember that these tables are examples only, and that they are presented here only to illustrate the difference between transfers and resource costs and to indicate how different analysts and decisionmakers can honestly argue about the actual costs of closure, even when those

Table 7

HYPOTHETICAL DISTRIBUTION OF THE COSTS (AND BENEFITS) ASSOCIATED WITH CLOSING A NUCLEAR GENERATING PLANT: FULL PASS-THROUGH

(In billions of 1983 dollars)

Item	Replacement Power	Taxes	One-time Impacts	Capital Costs	Secondary Costs	Total
Local						
Ratepayers	5.0	-1.0	1.0	4.0	--	9.0
Taxpayers	--	1.0	--	--	--	1.0
Other	--	-0.4	--	--	3.0	2.6
Net local	5.0	-0.4	1.0	4.0	3.0	12.6
Other U.S.						
Bondholders	--	--	--	-1.5	--	-1.5
Shareholders	--	--	--	-1.5	--	-1.5
Taxpayers	--	0.2	--	--	--	0.2
Other	--	0.2	--	--	-2.0	-1.8
Net U.S.	5.0	0.0	1.0	1.0	1.0	8.0
Foreign nations	--	--	--	--	-0.5	-0.5
Resource costs	5.0	0.0	1.0	1.0	0.5	7.5

costs are estimated correctly.

The computations behind these tables assume that closure of the local nuclear units involves replacement generation from outside the region; that that generation requires purchasing fuel oil from at least one foreign source; and that the only taxes of interest are local taxes on property and federal taxes on consumption and income. A positive entry in the table represents a cost, a negative entry is a savings or benefit to someone.

The additional cost of the alternative generation over the previous nuclear generation (an assumed $5 billion in the example) is passed directly to the local ratepayers. So is the net one-time cost (assumed to be $1 billion). These items are fully represented as direct charges to ratepayers and they are also fully classified as true resource costs. Even in this full pass-through case, however, these are the only items that display those characteristics.

Taxes, whether paid by ratepayers on their utility bills, by utilities on their income, or by utility employees on their income and consumption, are not resource costs. They are transfers from individuals, partnerships, or corporations to governments. Table 7 treats taxes in a very simple manner by considering only two types. Property (and in-lieu) taxes on the closed nuclear units ($1.0 billion) are no longer paid by the utilities, received by the local governments, or charged to the ratepayers.

If the replacement power is generated in existing facilities, there will probably be no change in the property taxes paid on those facilities. Newly constructed facilities, on the other hand, will contribute additional taxes to the governmental units in which they are located, and these monies will need to be recouped from ratepayers. Either way, the net effect of these taxes when we consider all individuals and agencies will net to zero.

All forms of taxes balance out. Individual and business taxes levied on income, consumption, and trade from or induced by the generation of electricity will decrease in the region of the closed nuclear facility and increase in the region where the replacement power is now generated. If additional oil is purchased from abroad, tax receipts in that country may also increase. Even if, as is discussed below, for some reason the gains and losses in economic activity do not balance out and a net decrease (or increase) in regional incomes or business activity occurs, the tax payments and receipts still will. For illustrative purposes, the table shows federal tax receipts falling by $0.2 billion when the decrease in payments from the area of the closed plant ($0.4 billion) is greater than the increase in payments ($0.2 billion) from the region of the increased generating activity. The reduction in federal taxes is offset by a corresponding reduction in government benefits to the nation.

Capital costs associated with the closure are shown in the fifth column. Some capital costs represent transfers from ratepayers to bondholders and stockholders; $3 billion of this is shown in the table, split equally between bond- and shareholders. Other elements of capital costs may represent true economic costs. Return on capital is a resource cost, and some portion of incremental capital costs will represent a required increase in that return because of altered risk, altered risk perceptions, and/or altered risk preferences. The table assumes $1 billion of this type of capital cost.

The final cost item shown in Table 7 is the secondary costs, representing the regional changes in employment, production, and income that are induced by the changes in electricity generation and costs. Most of the reduced activity in the region of the closed facility will be offset by increased activity in other regions, but market imperfections usually will prevent a complete offset. The example shows $3 billion in reduced activity for the region of the closed plant and $2 billion in increased activity for other areas, resulting in a net cost of $1 billion. The table also indicates a $0.5 billion stimulation to the economy of the foreign oil supplier.

Several types of subtotals and totals are shown in Table 7. The bottom line shows the net resource costs associated with the closure of this hypothetical nuclear power plant. Resource costs include the costs of replacement power, the net one-time costs and savings, and some elements of the capital and secondary costs. The example indicates real costs of $7.5 billion.

The final column of the table shows the distribution of those costs and indicates why the preferences of different social and regional groupings of citizens and elected officials concerning closure may realistically differ. The local region containing the closed plant is the big loser. In the example its losses total nearly twice the "net" cost. Real costs to the region include rate increases to cover shutdown, decommissioning, and increased generating costs and capital requirements. Induced changes in secondary activities also impose real costs on the region. Some of the local secondary costs may be alleviated by the "benefit" of not having to pay federal taxes on the forgone income, but a major portion of the secondary costs will remain as a local burden.

Note another point concerning the taxes. So long as the ratepayers are located in the local district, the reduction in property tax receipts on the closed plant is not an additional cost to the region. The district is not receiving the taxes, but, on the other hand, its citizens are not paying them. The net effect of all taxes paid by the local citizens may, in fact, act to slightly alleviate some of their increased costs.

The central portion of the table indicates that people and businesses located outside the closure area may benefit from the closure. Bondholders and stockholders will probably be distributed throughout the country so that transfers from ratepayers to these groups will be mainly transfers out of the local region. And the increased generating activity in the plants that have taken up the slack for the closed units will bring increased income and business activity to their respective regions. These effects will offset a substantial portion of the losses felt in the region containing the closed units so that the net impact of the closure on the U.S. as a whole will be much less than its impact in that one region.

Finally, the example indicates that the purchase of additional oil from a foreign, possibly an OPEC, nation would directly increase that nation's petroleum production, foreign currency reserves, and governmental revenue from taxes, and, if slack exists in its general economy, might stimulate further activity. Any such gains would offset the net world-wide cost of the closure. They would typically, however, have little influence, one way or another, on the feelings of the U.S. citizens residing near the closed nuclear facility.

Table 7 examined a distribution of costs that might arise if the "full" costs of closure could be passed through to ratepayers. Several items change when we examine a partial, say a half, pass-through scenario. Table 8 illustrates some of the possibilities for such a case. This table is based on the same assumptions and uses the same hypothetical resource costs as Table 7, but transferring half of the direct costs of closure from ratepayers to stockholders will affect the costs experienced by the regional as well as the social distribution of the costs. These are shown in the table. The distributional changes

Table 8

HYPOTHETICAL DISTRIBUTION OF THE COSTS (AND BENEFITS) ASSOCIATED WITH CLOSING A NUCLEAR GENERATING PLANT: HALF PASS-THROUGH

(In billions of 1983 dollars)

Item	Replacement Power	Taxes	One-time Impacts	Capital Costs	Secondary Costs	Total
Local						
Ratepayers	2.5	-1.0	0.5	4.0	--	6.0
Taxpayers	--	1.0	--	--	--	1.0
Other	--	-0.4	--	--	3.0	2.6
Net Local	2.5	-0.4	0.5	4.0	3.0	9.6
Other U.S.						
Bondholders	--	--	--	-1.5	--	-1.5
Shareholders	2.5	--	0.5	-1.5	--	1.5
Taxpayers	--	0.2	--	--	--	0.2
Other	--	0.2	--	--	-2.0	-1.8
Net U.S.	5.0	--	1.0	1.0	1.0	8.0
Foreign nations	--	--	--	--	-0.5	-0.5
Resource costs	5.0	--	1.0	1.0	0.5	7.5

may also affect the real costs of closure by increasing the capital costs, possibly to such an extent that the utility cannot continue to operate any of its plants, increasing (all types of) costs still further. Table 8 does not attempt to deal with those more profound effects.

The matrix format of Tables 7 and 8 has at least three benefits. By indicating at least most of the different costs and affected groups, it (1) encourages the identification and estimation of most major costs, (2) aids in determining which groups will be most affected by the different types of costs, and thus (3) identifies the cost trade-offs that may exist between and among the different groups. Tables similar to 7 and 8 should be constructed whenever closure costs are estimated or discussed.

DISCUSSION

The discussions and findings of this study drew mainly from information from IP and Zion but can be generalized to other situations. For example, decisions concerning the opening of Diablo Canyon, the completion of Shoreham, or the abandonment of Seabrook 2 and of multiple units of the Washington Public Power Supply System and of Tennessee Valley Authority projects all involve similar considerations. Each case involves billions of dollars; each involves the financial viability of at least one large utility; each involves several regulatory agencies (often operating at cross-purposes); and each involves a high level of public interest (including different representations of "the" public interest as well as definitions of "the" closure costs).

For example, several groups of interested parties recently released estimates of the costs of not completing and bringing on-line the Shoreham nuclear power generating facility, a nearly completed, 809 MW plant located 55 miles from Manhattan on the North Shore of Long Island. Estimates of the Shoreham non-completion costs have been structured quite similar to the IP estimates: They concentrate on alternative generation costs, ignore most capital and secondary costs, and, as a consequence, substantially underestimate at least the regional costs of closure.

Several of the more recent estimates are interesting, however, in that they are beginning to grapple with the concept of differential regional costs. One report (Armbruster et al., 1983), prepared by the Hudson Institute for the Long Island Lighting Company (LILCO), the owner of the Shoreham facility, estimated that the present value of the direct and indirect economic benefits for Long Island from operating rather than abandoning Shoreham (calculated over the next 20 years) would be greater than $4 billion 1983 dollars. The documentation of the estimate is less than clear but it appears that the cost of closure is composed of $2 billion in increased generating costs and another $2 billion in "lost" property taxes.

A second report was prepared by ESRG (1983) for Suffolk County. Suffolk County officials, in whose jurisdiction the plant is located, have been attempting to block completion and operation of the plant because they say it would be impossible to evacuate residents of the surrounding area in the event of a radiation accident. The County contends that the difference in cost between operation and abandonment would be small, and that abandonment might even be cheaper. The County/ESRG estimate of the costs of non-completion was reported by the *New York Times* (NYT 10/20/83) to total less than $0.5 billion.

A third estimate was compiled for a commission set up by Governor Cuomo of New York State. Wald (11/22/83) reported that the Commission, named after its president, Dr. John H. Marburger, was "near a conclusion that the savings would have been well under $1 billion when it was thought that the plant could be finished for $3.4 billion," and that it expects construction costs to increase to perhaps $4 billion, further reducing the costs of closure. Unfortunately, the membership of that commission was so diverse that it could not agree on specific findings or recommendations.

These estimates differ significantly: Wald (10/14/83) reported that Suffolk County puts the differential increase in electricity prices at 2.2 percent if Shoreham does not open; the Marburger commission says it would be about 6 percent; and LILCO's estimate is 18 percent.

In addition to the three estimates cited above, the *New York Times* (NYT 10/20/83) presented some figures of its own suggesting that a 30-year operating horizon should yield differential generating costs of slightly more than $1 billion, savings on decommissioning costs of perhaps $65 million (in present value terms), and some $565 million in LILCO property taxes, so that the "net economic cost of abandonment to the island" would be about $1.5 billion.

Table 9 illustrates the benefits of the matrix format developed in Sec. IV for collecting and presenting information concerning utility closures by summarizing the *New York Times* estimates.

The matrix illustrates how limited the analysis of Shoreham costs has been. Only generating costs and taxes are quantified, and even those have been aggregated incorrectly. The net of these closure costs is $1.0 billion rather than $1.5 billion, and the impact on Long Island is probably less than that.

Table 9

HYPOTHETICAL DISTRIBUTION OF THE COSTS (AND BENEFITS) ASSOCIATED WITH ABANDONING SHOREHAM: FULL PASS-THROUGH

(In billions of 1983 dollars)

Item	Replacement Power	Taxes	One-time Impacts	Capital Costs	Secondary Costs	Total
Long Island						
Ratepayers	--	--	--	--	--	--
Taxpayers	--	--	--	--	--	--
Other	--	0.5	--	--	--	0.5
Net Long Island	--	0.5	--	--	--	0.5
Other LILCO service area						
Ratepayers	1.0	-0.5	--	--	--	0.5
Bondholders	--	--	--	--	--	--
Shareholders	--	--	--	--	--	--
Taxpayers	--	--	--	--	--	--
Other	--	--	--	--	--	--
Net service area	1.0	0.0	--	--	--	1.0
Other U.S.						
Bondholders	--	--	--	--	--	--
Shareholders	--	--	--	--	--	--
Taxpayers	--	--	--	--	--	--
Other	--	--	--	--	--	--
Net U.S.	1.0	0.0	--	--	--	1.0
Foreign nations	--	--	--	--	--	--
Resource costs	1.0	0.0	--	--	--	1.0

SOURCE: Original data from *New York Times* editorial, 10/20/83.

As the discussion in the last section indicated, if the ratepayers for Shoreham's power are not located on Long Island, then the property taxes paid on Shoreham facilities and raised through the electricity rates can indeed be viewed as transfers "to the island" from elsewhere. These tax receipts represent a significant portion of the total revenue of the local governments.

In the full pass-through case, all of the $1.0 billion for alternative generating costs would be passed on to ratepayers. If the utility does not pay property taxes on the Shoreham property, however, those rates would be reduced by that estimated $0.5 billion,[1] lowering the net impact for the ratepayers to $0.5 billion. Long Island residents lose the $0.5 billion in reduced property taxes. They would also assume some portion of the ratepayers' loss, as a portion of the electricity would have been consumed on the Island.

Presenting one of the partial pass-through cases that have been estimated would provide entries for more of the cells in the matrix, but still there would be many dashes indicating items that have thus far not been even roughly quantified. In particular, secondary effects induced by the activities at Shoreham would certainly be important for Long Island, and the capital costs of closure would seriously threaten the utility's financial viability.

This short discussion of the current state of the Shoreham discussions illustrates the difficulty that analysts, public-minded organizations, and local officials are having with conceptualizing and estimating closure costs. The example suggests that all cost estimates constructed for testimony before regulatory groups should be required to conform to a matrix framework similar to the ones shown above, with cost categories displayed along one dimension and affected groups along the other. This would help both to reduce the confusion and double-counting that now occur and to highlight costs that have not been quantified. Failure to adopt such a full-costing framework will continue to allow important public-policy decisions to be based on erroneous and incomplete information, as they are at present.

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[1]Of course, the alternative generation activities may increase property taxes elsewhere.

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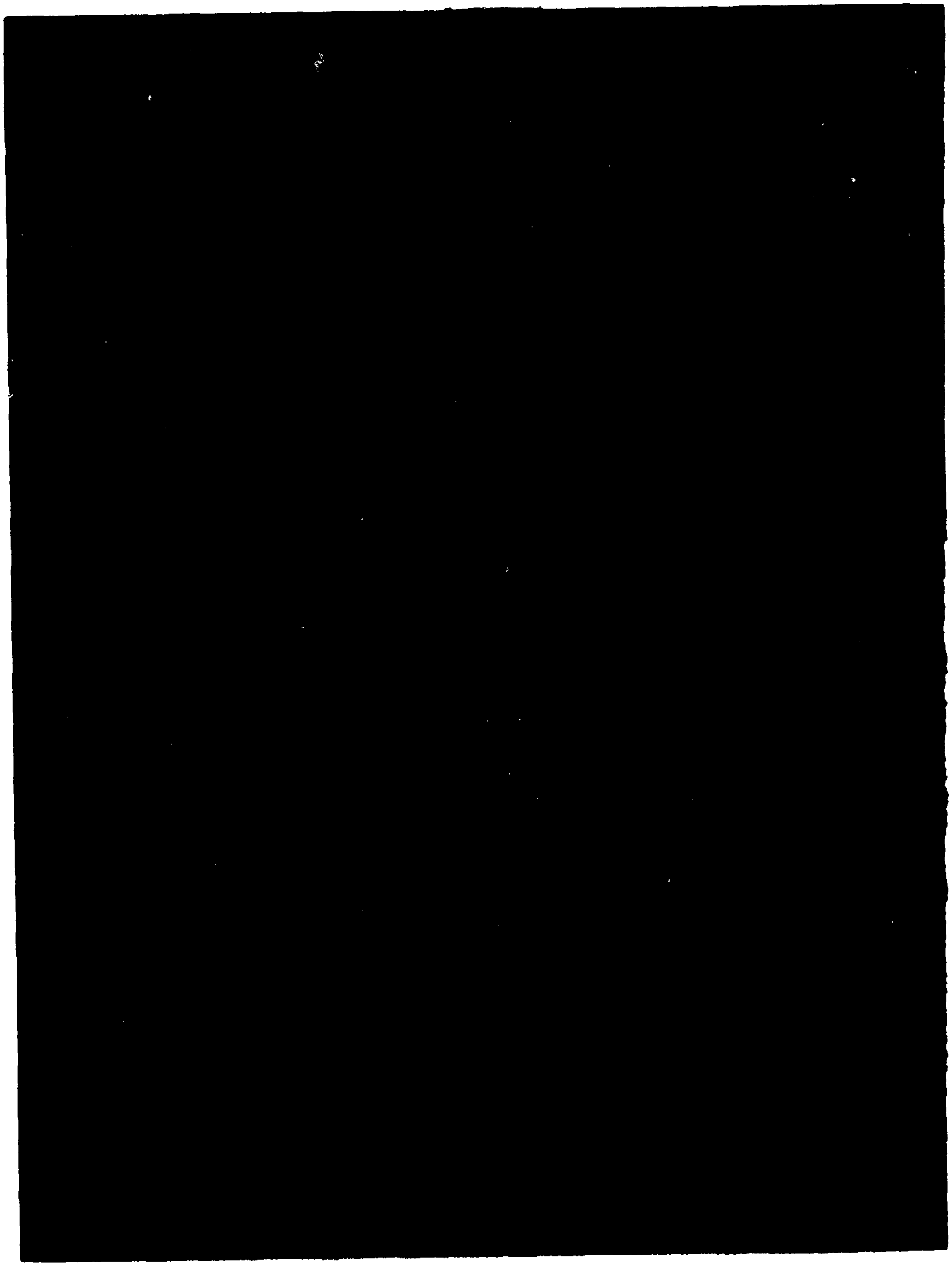
Fig. 8 -- Discounted closure costs for Indian Point, by year of closure, expressed as percent of the costs incurred with 1980 closure



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